Cost Control Options: Follow-up to May 24, 2017 Discussion on 2017 Long-Term Energy Plan Base Case

Prepared for Discussion with Ministry of Energy

May 31, 2017

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Context and overview

- The IESO delivered a long-term planning analysis to the Ministry of Energy on May 24, 2017. The analysis focused on capacity balances, energy production, carbon emissions and costs.

- For immediate follow-up, the Ministry of Energy asked the IESO to (a) compare the IESO's current projection of residential electricity bills to the 2013 LTEP projection; and (b) consider options to reduce residential electricity bills

- The Ministry of Energy's requests are addressed in the following slides. Five scenarios are explored:

  Case 1: A basecase*

  Case 2: Replacement of Thunder Bay and Atikokan generating stations at a more competitive cost at contract expiry

  Case 3: Funding conservation through the GGRA starting in 2018

  Case 4: Funding a percentage (10%) of renewables costs through the GGRA starting in 2017

  Case 5: Not proceeding with MicroFit 2017 and FIT 5, and exiting LRP1 contracts

  - The above are analyzed cumulatively: each scenario incorporates the cost control measures of all scenarios that precede it. Residential bills are projected for each scenario, total costs and industrial rates are also reported.

  - Additional options are considered conceptually, pending completion of analysis underway at this time. These include revisiting ICI eligibility and adapting plans for Pickering extended operations.

*Base case reflects achievement of 2013 LTEP conservation targets and supply assumptions consistent with the Ministry of Energy's 2017 Long-term Energy Modelling Assumptions document available at Appendix)

Summary: The current projection for residential electricity bills is generally, but not always, lower than in the 2013 LTEP. Cost control measures could reduce residential bills to below 2013 LTEP projections.

- Base case with OFHP but without further cost control measures: currently projected residential bills are lower than in the 2013 LTEP for most years, except in 2029 and 2030, where they are higher by roughly $1/Month and $4/Month, respectively

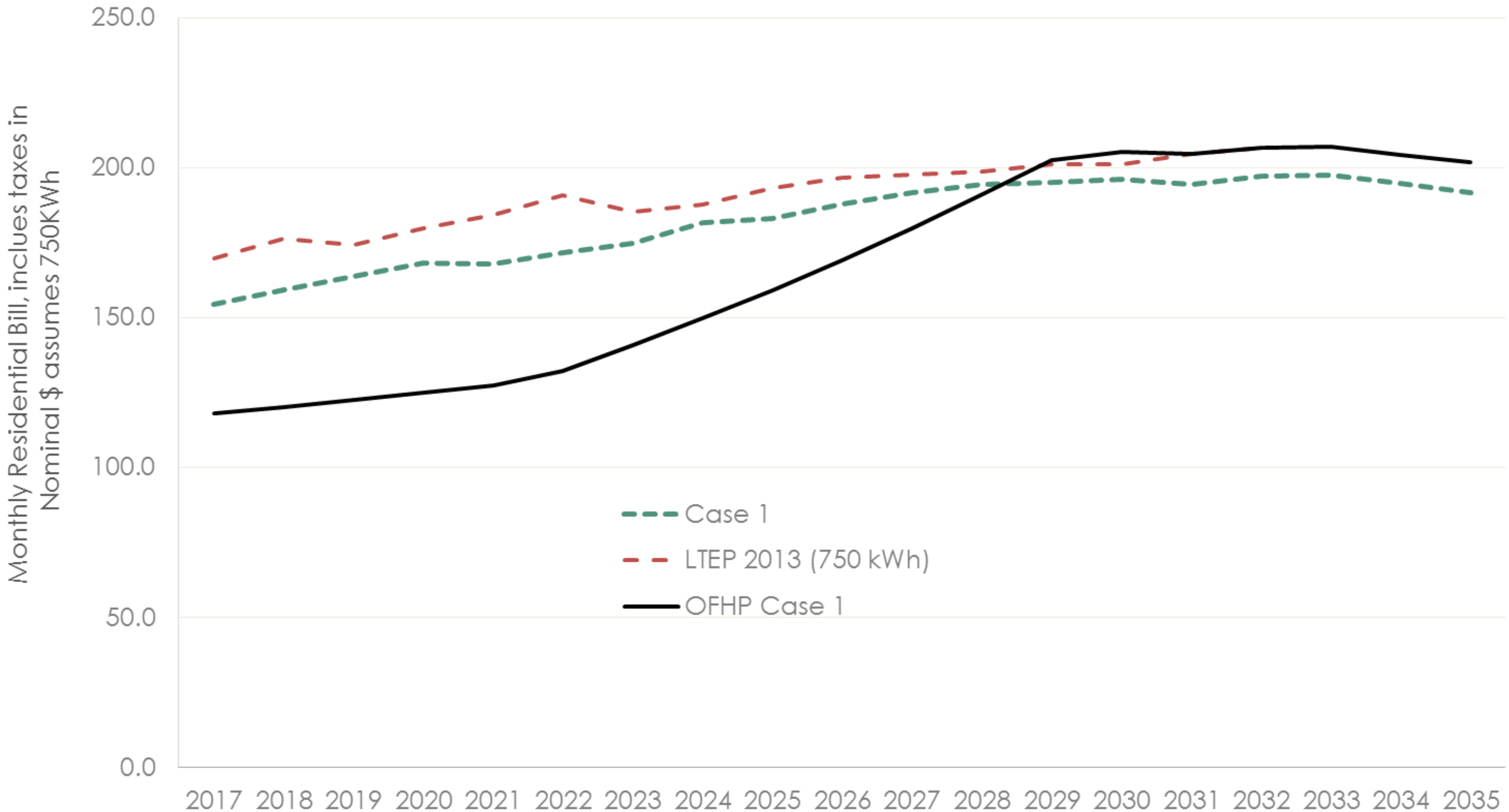
- In conjunction with the OFHP, replacing the Thunder Bay and Atikokan generating stations at a more competitive cost and also funding conservation through the GGRA starting in 2018 would result in lower residential monthly bills than projected in the 2013 LTEP in all years over the planning period

- Cost control measures as identified in Cases 3 to 5 could reduce residential bills by up to $5 per month compared to the 2013 LTEP by 2032. This difference is interpreted as within the range of modelling approximation.

- The cost control options considered here generally fall into four categories:
  a. Reducing investment and operating costs (i.e. buying less and/or buying-operating at a lower cost)
  b. Deferring ratepayer costs (i.e. OFHP)
  c. Shifting ratepayer costs (i.e. GGRA)
  d. Reallocating costs among ratepayer classes (i.e. revisiting ICI eligibility)

- Of the five scenarios considered, most fall into the “deferring” and “shifting” categories outline above: this is a function of Ontario’s current state of electricity resource commitment. Options that fall into category “a” include not proceeding with FIT5 and Microfit 2017 and replacing Thunder Bay and Atikokan at a lower cost. Limiting the scope of ICI eligibility might not only reallocate costs, but also reduce total costs.

Case 1: The base case monthly residential bill projection with OFHP is generally lower than in the 2013 LTEP, with the exception of the years 2029 and 2030. The annual escalation is 6.3% per year between 2022 and 2028. The basecase monthly residential bill projection without OFHP is lower than the 2013 LTEP projection in all years.



- Basecase trajectory with OFHP is comparable to the original Ministry of Energy projection of the OFHP used for Cabinet briefing. See Appendix for illustration.

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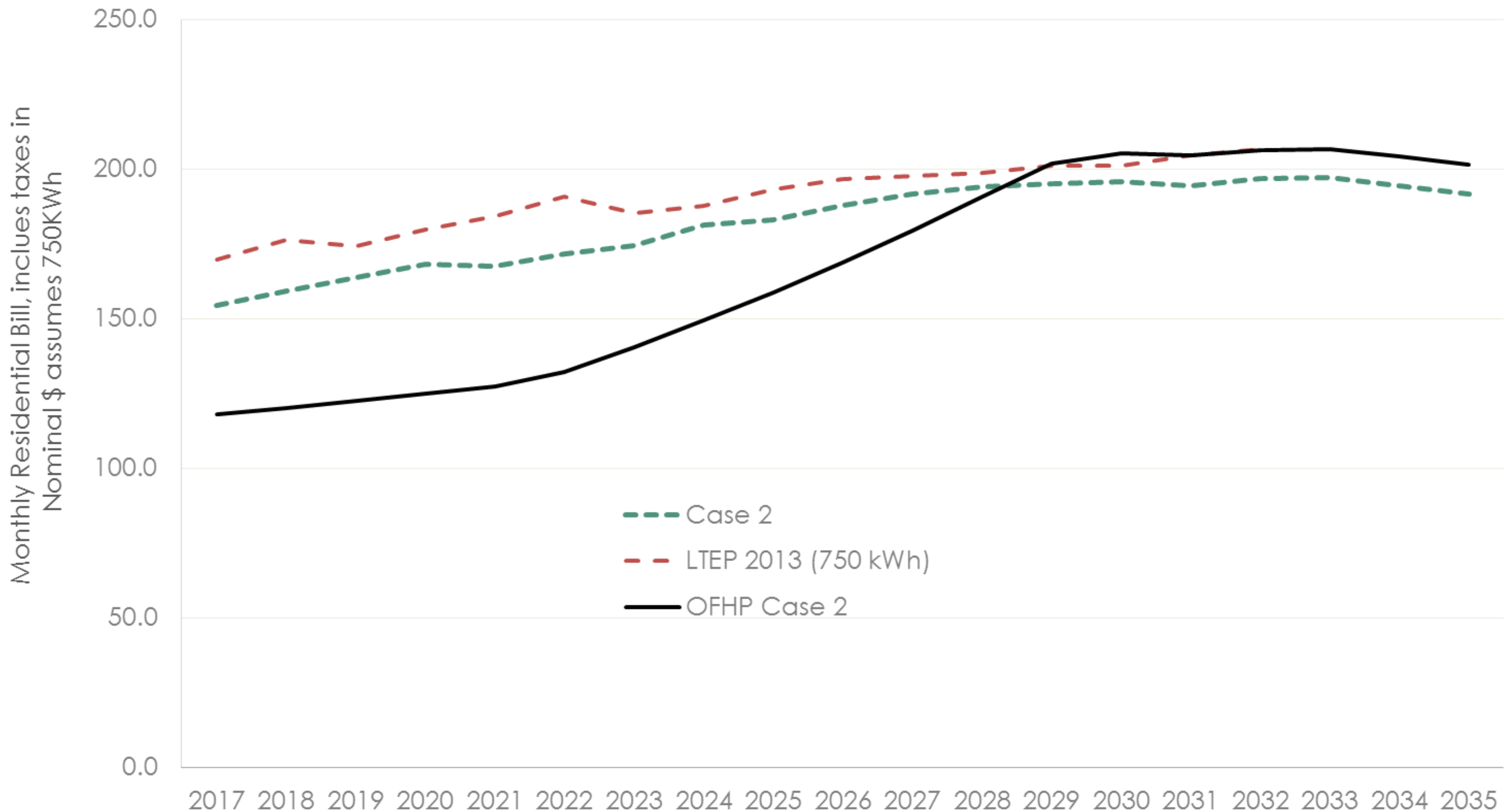
Case 2: In conjunction with the OFHP, replacing the Thunder Bay and Atikokan generating stations at a more competitive cost would result in lower residential monthly bills than projected in the 2013 LTEP for almost the entire planning period, with the exception of the years 2029 and 2030



- Cumulative savings of over $900 Million would be achieved with a more market competitive cost for contract expiry of Thunder Bay and Atikokan. Details available in Appendix.

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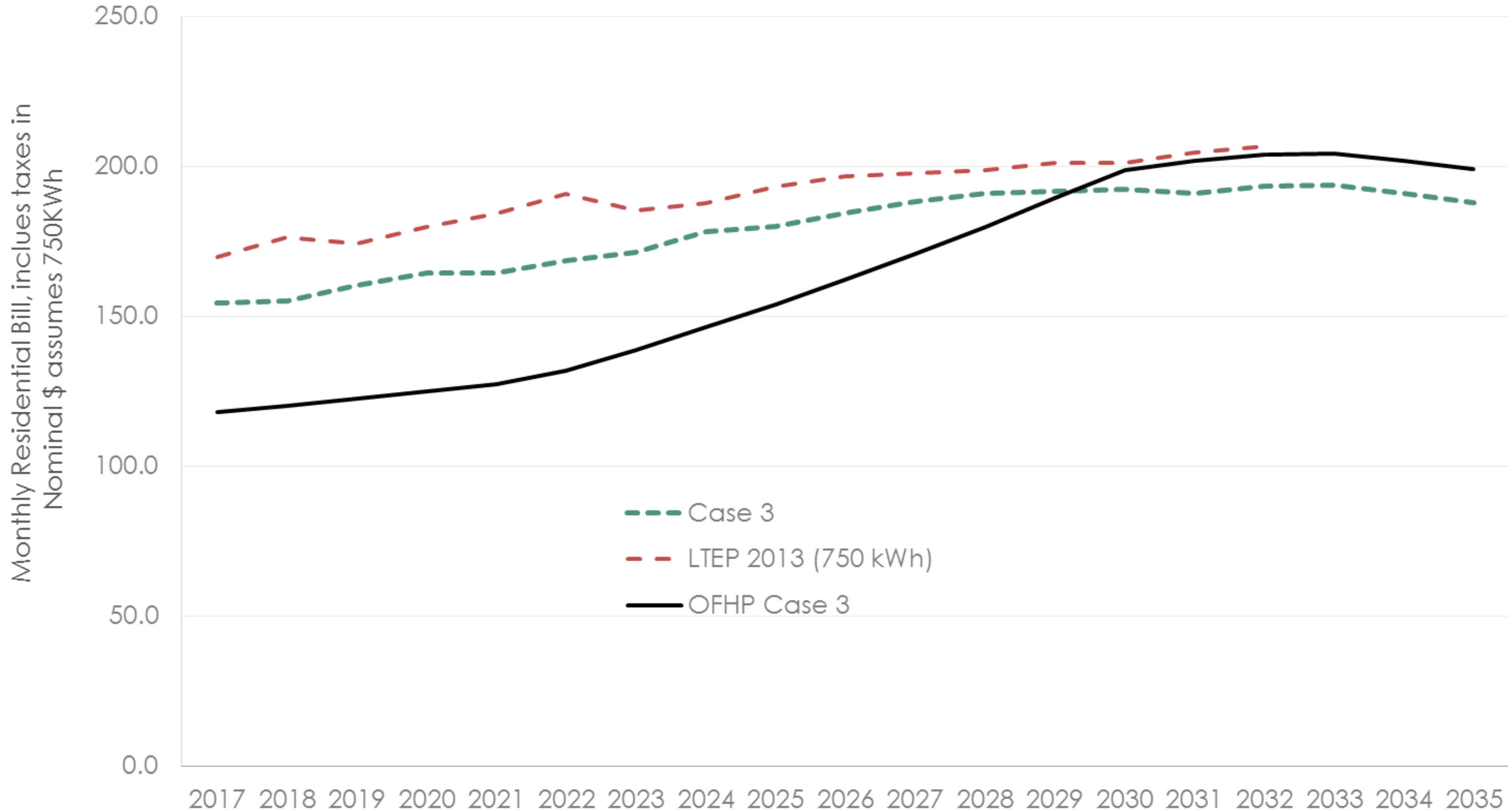
Case 3: Shifting conservation costs into the GGRA would further reduce residential bills relative to the 2013 LTEP. Bills under such a scenario would remain below 2013 LTEP projections in each year between 2017 and 2035. The annual escalation would be about 5.3% per year from 2022 to 2028.



- Cumulative cost of $54 Billion shifted into GGRA. Details available in Appendix.

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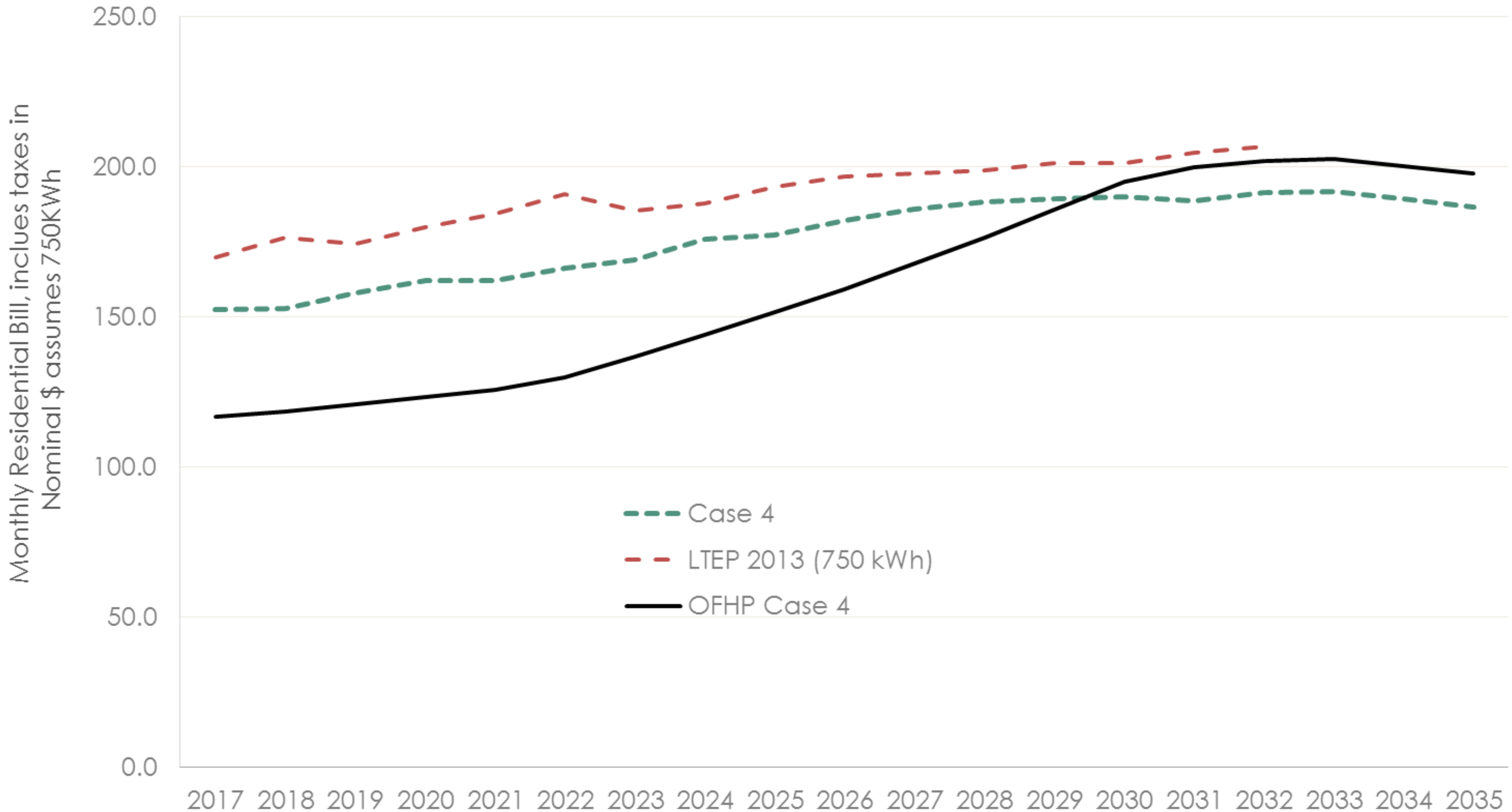
Case 4: Shifting 10% of Ontario`s annual renewable costs to the GGRA would reduce ratepayer costs by about $285 million per year and result in additional residential bill savings compared the 2013 LTEP



- Cumulative cost of $7.4 Billion shifted into GGRA. Details available in Appendix.

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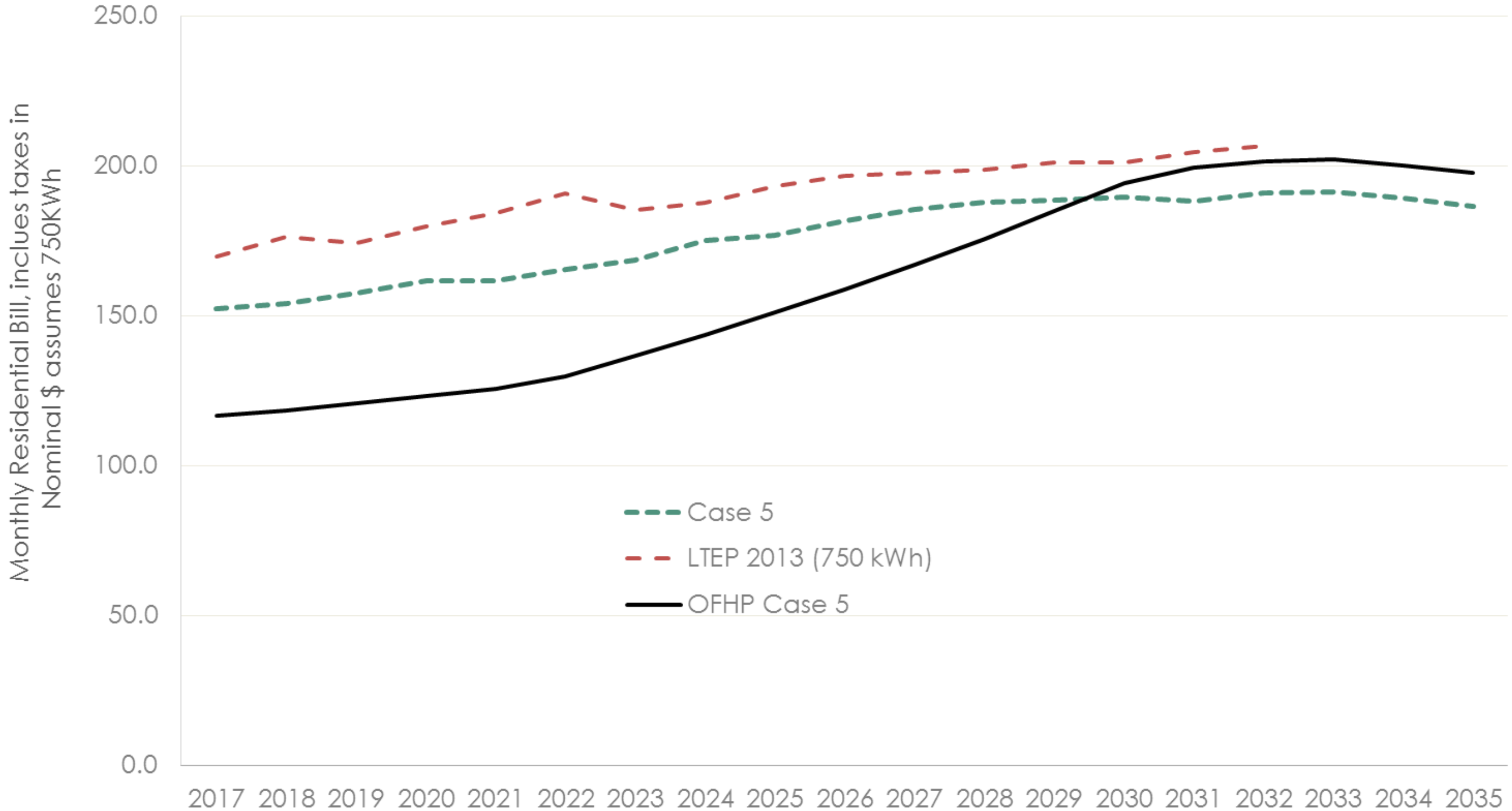
Case 5: Not proceeding with FIT5 and Microfit2017 and existing commitments under LRP1 would further reduce residential bills. The projected costs of these programs is between $70 Million and $118 Million per year between 2019 and 2035, for a cumulative total cost of about $1.5 Billion. Net cost savings could be achieved after accounting for the cost of exiting contracts.



- Cumulative savings of over $1.5 Billion would be achieved by not proceeding with FIT5 and Microfit 2017 and existing LRP 1. Details available in Appendix.

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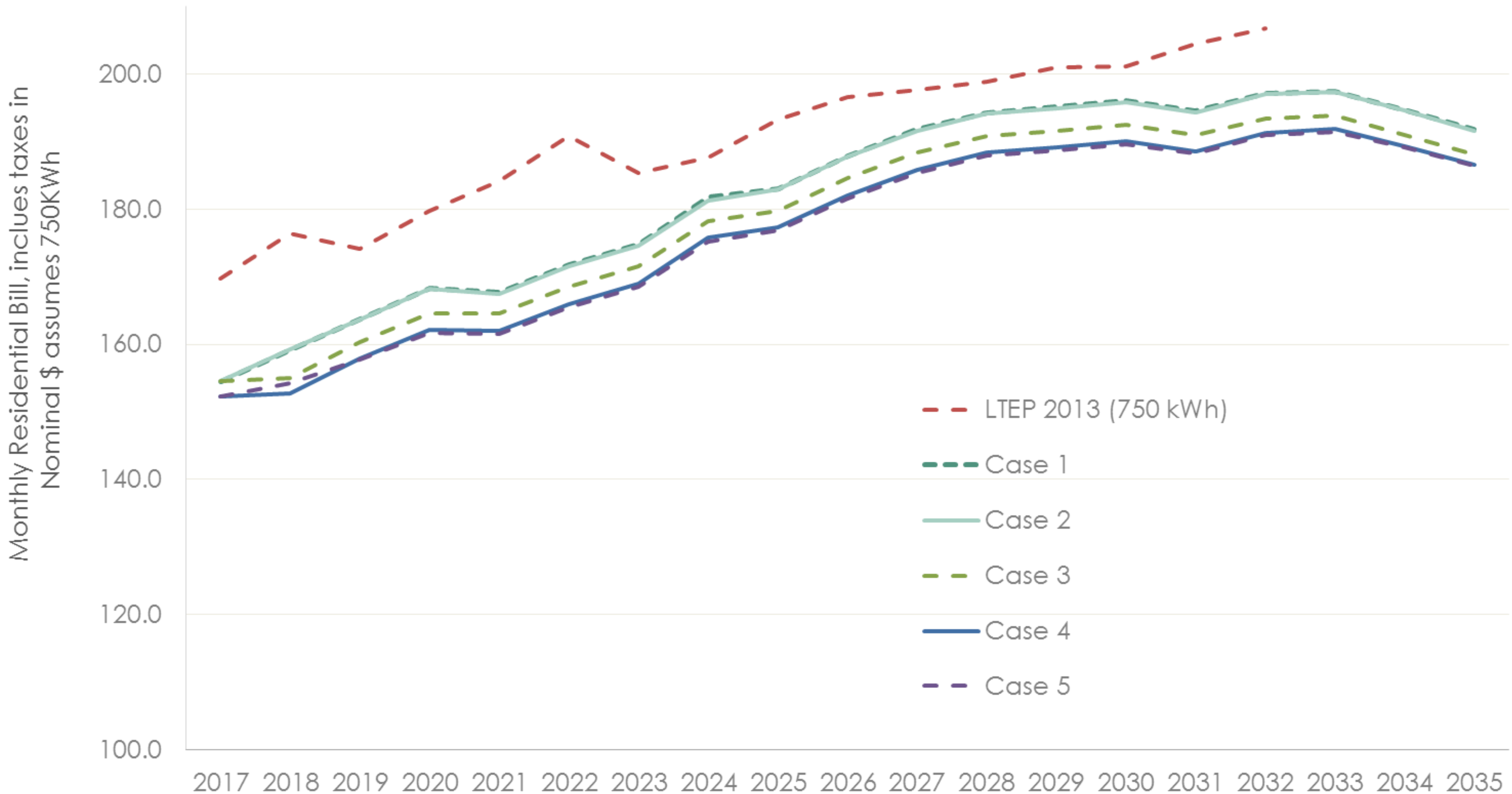
Overview of all Cases without OFHP: residential bills under all cases would remain below 2013 LTEP projections in all years, prior to accounting for the OFHP



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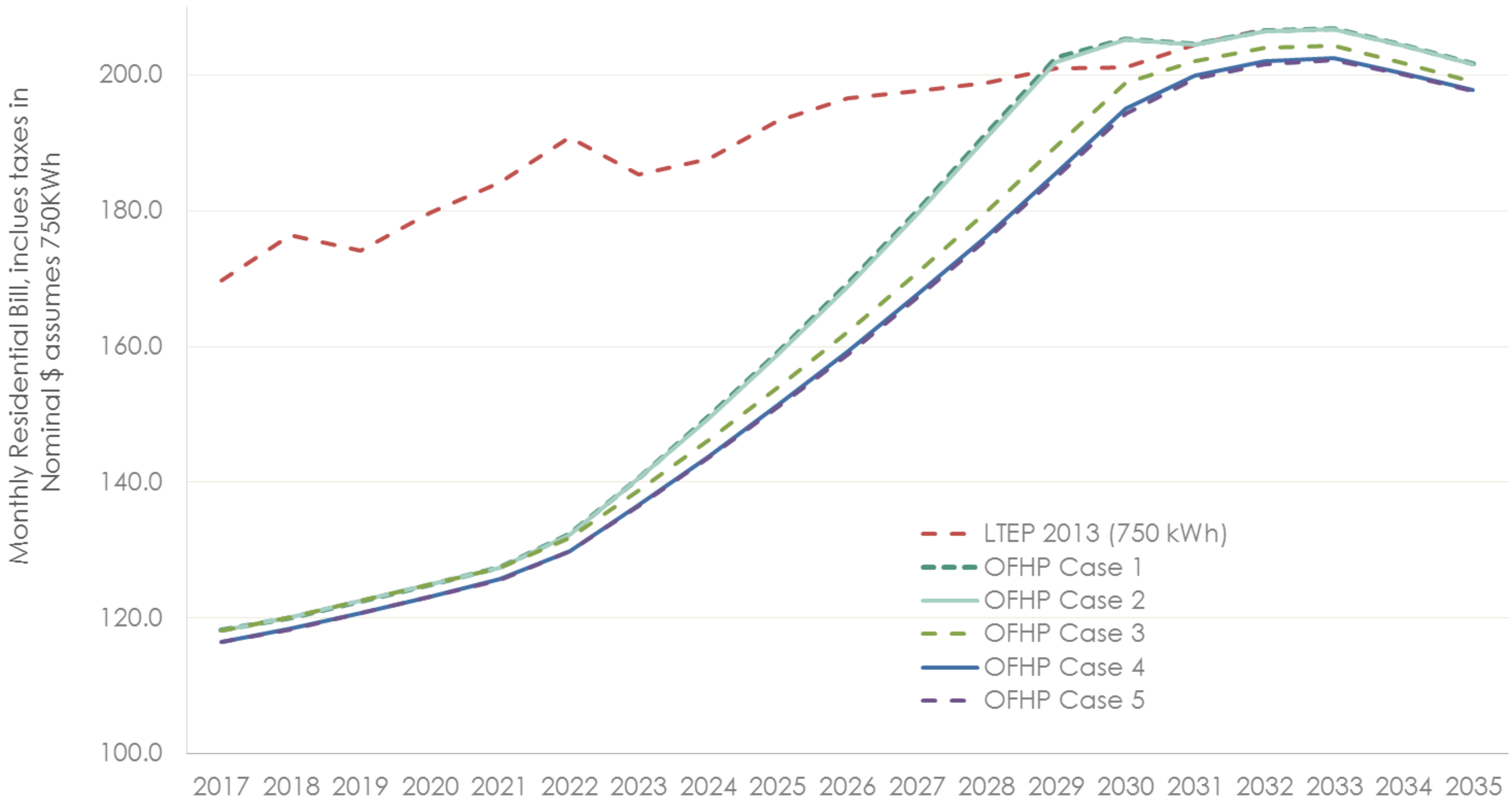
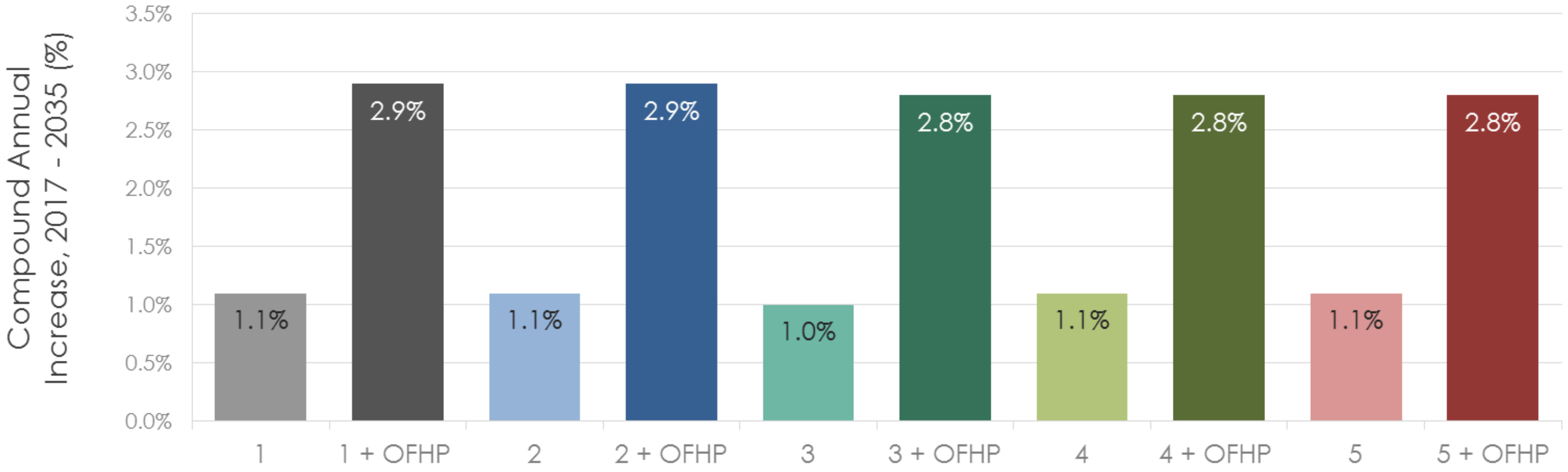
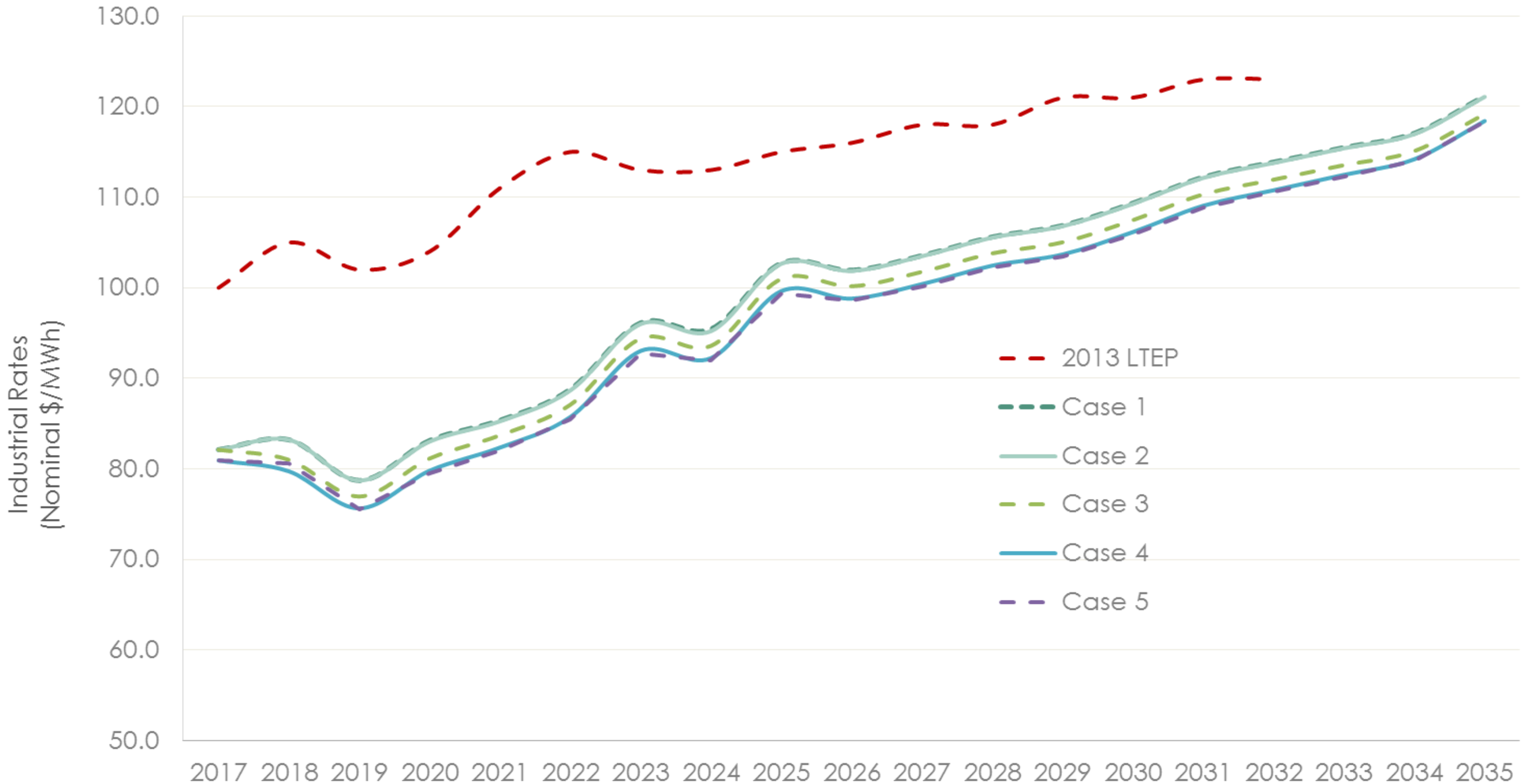
Overview of all cases with OFHP: After accounting for the OFHP, bills would be notably lower relative to 2013 LTEP projections over the next decade or so, then would return to bills consistent with the 2013 LTEP projection. Cases 1 and 2 would exceed the 2013 LTEP projections in some years; cases 3 through 5 would remain below 2013 LTEP projections in all years, and by 2032 it will lower the bills by about $5/Mth



Overview of all residential cases, continued: without the OFHP, all monthly residential bills projections would increase at less than the rate of inflation. For all projections with the OFHP, compound annual residential rate increases would exceed inflation, since rates would start from a lower level.



Overview of industrial rates for all cases: projected industrial rates are below 2013 LTEP projections. For the highest case, Case 1, the industrial rates are lower between $9 and $26 dollars per MWh. The net difference between Case 1 to Case 5 ranges between $1 to $4 dollars per MWh.



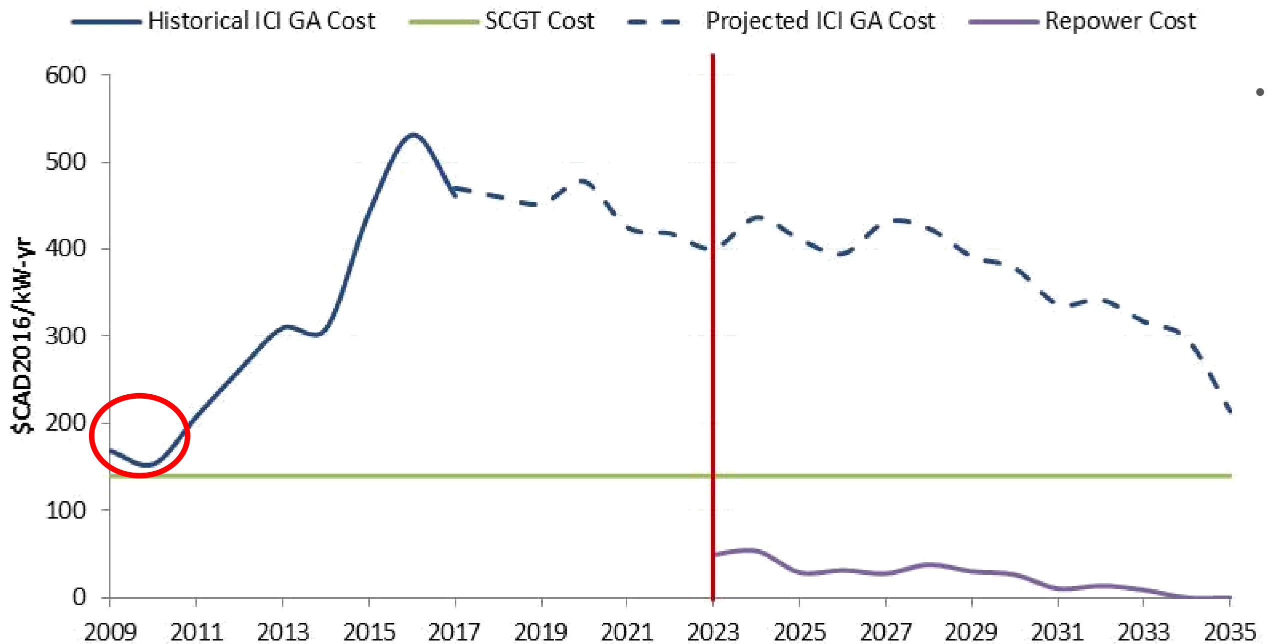
Additional considerations: the effect on costs of an alternative scope of Pickering extended operations is not well understood at this time. Work is underway to get a better sense of implications of a longer or shorter extended operations period. Work is also underway to better understand cost impacts of revisiting ICI eligibility. Some preliminary considerations are outlined below.

- Pickering extended operations: Previous IESO assessments have shown that Pickering extended operations has the potential to reduce costs, but is not without its potential pitfalls: its economic merits are sensitive to variables such as Pickering cost and performance, natural gas price and capacity and energy needs. The IESO has also noted that extending all Pickering units to the end of 2024 can lead to a disbenefit and that reducing the number of units extended would be worth exploring in light of Pickering's contribution to surpluses, etc.

- On May 24, 2017, the Ministry of Energy verbally indicated that extending some or all Pickering units to 2026 might be an emerging option. The economic merits of this option should be considered against the latest supply/demand outlook and reflect OPG's best available estimates of Pickering cost and performance. At this point, the effect of extending units to 2026 is unclear.

- ICI: The ICI program shifts some fixed costs away from participating customers and places those costs onto non-participating (e.g. residential) customers. The definition of who is eligible for ICI has expanded in recent times. Narrowing ICI eligibility could have the effect of reducing the amount of fixed costs passed on to residential customers. However, narrowing ICI eligibility could lead to lower ICI participation and therefore lower peak reductions. Lower peak reductions could increase the need for supply resources. As shown on the following slide, preliminary IESO analysis suggests the ICI is more expensive than alternative resource options. Narrowing ICI eligibility could therefore also reduce total costs (i.e. in addition to relieving non-participants from some fixed costs).

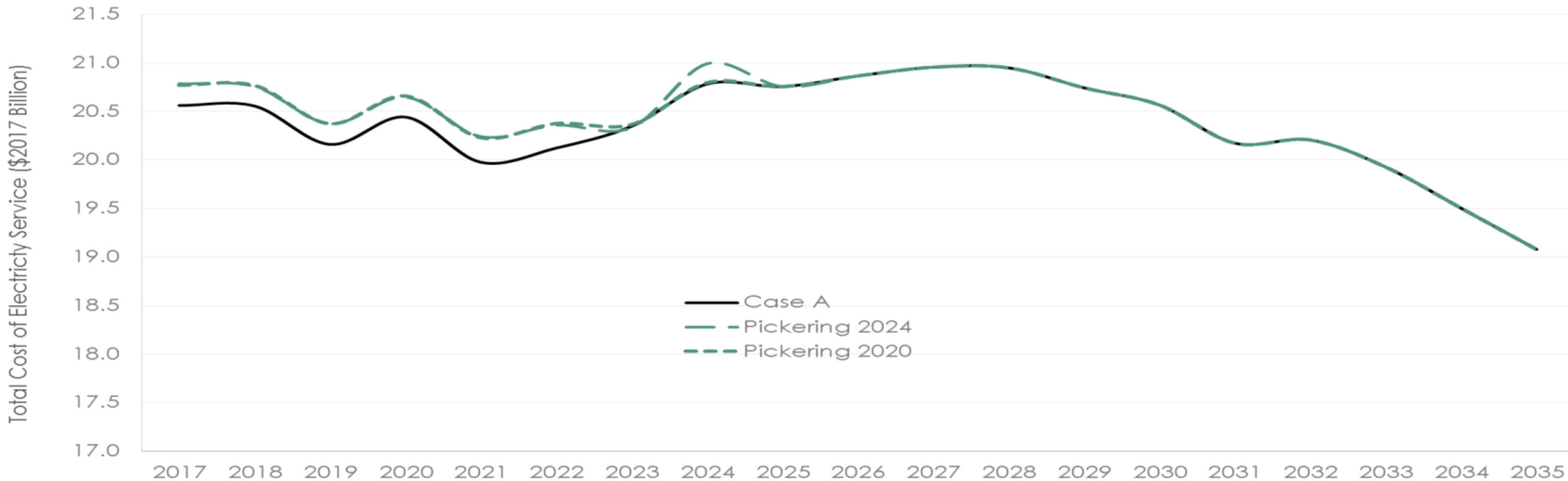
Additional considerations - Illustration: the cost of ICI has historically been greater than Ontario's avoided capacity cost. Options such as a new-build plant, demand response or repowered plant could provide capacity at a lower cost than ICI.

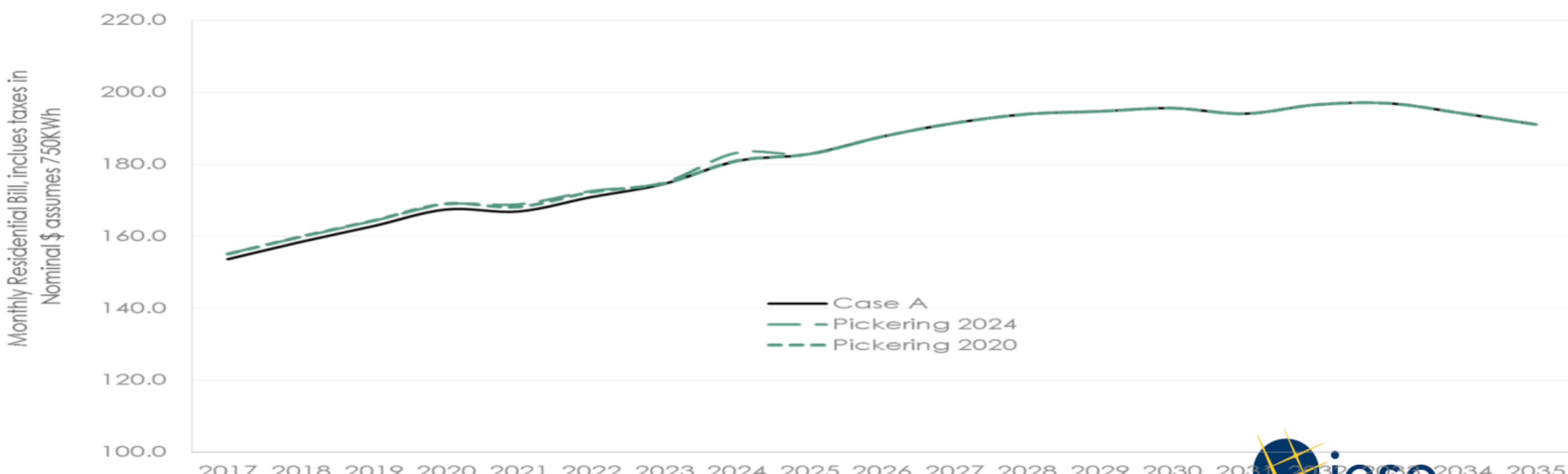


- The cost of capacity through ICI program is decreasing (dashed blue line) however, it does not decrease below the cost of new build capacity within this timeframe. The cost of ICI capacity remains higher than system avoided cost.

- When ICI program was initiated, the avoided system cost of new capacity (SCGT Cost) was in-line with the cost of capacity through the ICI program (circled in red)
- The cost of capacity through ICI program has increased significantly (solid blue line)
- Capacity needs start in the mid 2020s
- This capacity need could be met through a combination of repowering expiring contracts (purple line) or new peaking capacity (represented by SCGT cost in green). The system avoided cost in these years would be somewhere between these lines.

Additional considerations - another illustration: Two cases were considered with Pickering A units 1 & 4 retiring in 2020 and Pickering A units extended to 2024. Both scenarios resulted in a total cost increase and increase in monthly residential bills: the current extended operations schedule seems to have hit a sweet spot among options considered to date. Consideration of Pickering extended operations beyond 2024 will require the best available information from OPG.





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Appendix:

- Ministry of Energy’s 2017 Long-Term Energy Plan Modelling Assumptions document, April 6 2017

- Further detail on analysis of five scenarios

Ministry of Energy’s 2017 Long-Term Energy Plan Modelling Assumptions, April 6 2017 Document (1)

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MINISTRY OF ENERGY'S 2017 LONG-TERM ENERGY PLAN MODELLING ASSUMPTIONS

This document summarizes the modelling assumptions for the reference outlook to inform the Ministry of Energy’s 2017 Long-Term Energy Plan (“2017 LTEP”).

The document reflects the IESO’s understanding of the assumptions to be assumed for the 2017 LTEP based on IESO/ENERGY discussions between February and April 2017 and comments received from ENERGY staff on April 1, 2017.

In order to proceed with analytics, the IESO is seeking Ministry sign off on this document no later than Friday April 7, 2017

Section 1 – Assumptions

Outlook Timeframe

- The IESO will model the LTEP for the period 2017 to 2035 to align with the timeframe presented in the 2016 Ontario Planning Outlook (OPO).

Demand

- It is the IESO’s understanding that ENERGY’s preference is to consider a single demand outlook as the reference forecast. The reference demand forecast for the 2017 LTEP will be OPO Outlook B with the addition of electric vehicle (EV) demand assumptions per Outlook D (i.e., 2.4 million EVs by 2035).
- It is the IESO’s understanding that ENERGY’s preference is to consider a range of sensitivities around the reference demand forecast, with the range of sensitivity starting in 2026. Therefore, two sensitivities will be developed around the reference demand forecast to illustrate higher and lower ranges beginning in 2026:
  - The lower range will have similar assumptions to OPO Outlook A.
  - The higher range will assume higher household growth, higher new square footage growth in various commercial buildings, and greater growth in the industrial sector.
- Detailed energy/costing analysis will not be performed for the low and high demand sensitivities. Instead, their implications may be described qualitatively.

Conservation and Demand Response

- The 2013 LTEP targets 30 TWh of energy efficiency by 2032 and assumes that the near term target set in the Conservation First Framework and Industrial Accelerator Program of 8.7 TWh will be achieved by 2020.
- The IESO understands that ENERGY is seeking analysis on modeling a higher than 2013 LTEP conservation target within the OPO Outlook B. Based on discussions with the ADM and Michael Lyle, the IESO will perform analysis assuming 1) the 2013 LTEP conservation targets and 2) a higher conservation target.

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- The 2013 LTEP included a Demand Response target which includes Time-of-Use (TOU), Industrial Conservation Initiative (ICI) and demand response (DR) auction combined to meet 10% of peak demand by 2025. It is the IESO’s understanding that ENERGY requests to eliminate the demand response target that was established in 2013 LTEP for the 2017 LTEP base case. The IESO will assume for the 2017 LTEP base case that TOU and ICI will continue to persist throughout the planning horizon and any DR currently procured through the DR auction would continue to be available in future auctions. Should there be capacity needs moving forward, additional demand response could be procured through the capacity auction.

Supply

- The IESO will assume the nuclear schedule that is consistent with OPO, which reflects OPG’s current business plan and the amended Bruce refurbishment agreement:
  - Bruce as per the schedule in the finalized ABPRIA;
  - Pickering continued operations to 2022/2024 (Note from ENERGY: In March 2017, OPG Board approved operation of all six units to 2024 subject to system needs and project economics. As such, the additional two years is considered a supply option/scenario rather than a base case);
  - Darlington as per the finalized refurbishment schedule.
- It is the IESO’s understanding that ENERGY does not want to consider operation of all six Pickering units to 2024 as part of the analysis. The IESO will assume Pickering continued operations to 2022/2024 for the base case.
- The IESO will reflect the October 2016 Ontario-Quebec Electricity Trade Agreement.
  - Energy 2.3 TWh per year (2017 to 2022 inclusive) Quebec to Ontario;
  - 500 MW capacity per winter December to March (2016/17 to 2022/23 inclusive) Ontario to Quebec; and
  - 500 MW capacity Quebec to Ontario in return for delivery of 500 MW to Quebec in 2015/16 as part of original capacity swap.
- The IESO will reflect recently contracted new resources e.g. Chaudiere Falls Gatineau No.1 and Hull No.2 waterpower contracts.
- The IESO will assume the suspension of Large Renewable Procurement II and Energy From Waste Procurement as a result of the September 2016 direction.
- The IESO will assume FIT 5 and microFIT 2017 are the remaining renewable programs to be procured that are not yet online or contracted.
- The 2013 LTEP set renewable capacity targets of 10.7 GW for non-hydroelectric by 2021 and 9.3 GW for hydroelectric by 2025. The IESO will assume the elimination of hydro and non-hydro renewable targets and that there will be no further renewable procurements beyond FIT 5 and microFIT 2017 in the 2017 LTEP reference outlook.

Costs

Ministry of Energy's 2017 Long-Term Energy Plan Modelling Assumptions, April 6 2017 Document (2)

- The IESO will assume natural gas price forecast per the Sproule projection as of February 2017. Further updates to the gas price forecast will lengthen modelling timelines. The IESO will assess a lower and higher gas price forecast for sensitivity.

- The IESO will include new higher contracted price information for existing NUG contracts.

- The IESO will assume carbon cost as the reserve price (i.e., the floor price) projection in the 2017 LTEP base case, and the "updated CA-QC-ON Bloomberg Nov 2016" projection for the sensitivity.
  - Note that the reserve price projection is slightly different from the OPO forecast; it now includes the actual floor price for the March 2017 cap and trade allowance auction as notified in January 2017, and this value is inflated by 5% as per the cap and trade regulations and added an assumed inflation factor of 2%.
  - The "updated CA-QC-ON Bloomberg Nov 2016" projection has been provided to IESO via ENERGY.
  - See Appendix for the carbon price projection values.

- The IESO will assume OPG nuclear rates to be consistent with the revised OPG Rate Smooth received from Tim Christie on March 13, 2017. The IESO will use the OPG nuclear outage data received from Tim Christie on March 10, 2017, and the nuclear production data received from Tim Christie on March 13, 2017. No change to Bruce Power nuclear prices from OPO.

- The IESO will assume OPG hydro rates to be consistent with the data received from Tim Christie on March 23, 2017.

- Upon contract expiry, for modelling purposes, the IESO will assume the assets will continue to be available for the duration of the planning outlook (i.e. similar to Outlook B in OPO). This recognises that the system can benefit from a portion of ongoing value from these assets with some re-investment, rather than requiring complete new build to meet the demand. The results of the "Benefits Case Assessment of the Market Renewal Project" prepared by the Brattle Group indicates that the cost based methodology used in the 2016 OPO would generate slightly lower results than the market based methodology pricing for these assets after contract expiry. The capacity market will be the implementation mechanism that achieves these cost based values for these assets after contract expiry.

  For the 2017 LTEP, the following assumptions will be used for costing expired contracts:

	Contract Expiry Cost Assumptions
Natural Gas	The contract information converted to a generic gas plant with re-investment proportions assumptions per Hatch Report.
Wind	Based on LRP I, with a discounted capital cost re-investment assumption for end of life components and accounting for on-going value from the balance of the asset. This cost assumption is lower than that used in 2016 OPO.
Solar	Based on LRP I, except that future investments for end of life components that need to be replaced decline in cost to recognise technological improvements. This cost assumption is lower than that used in 2016 OPO.

Industrial Rates and Residential Bills

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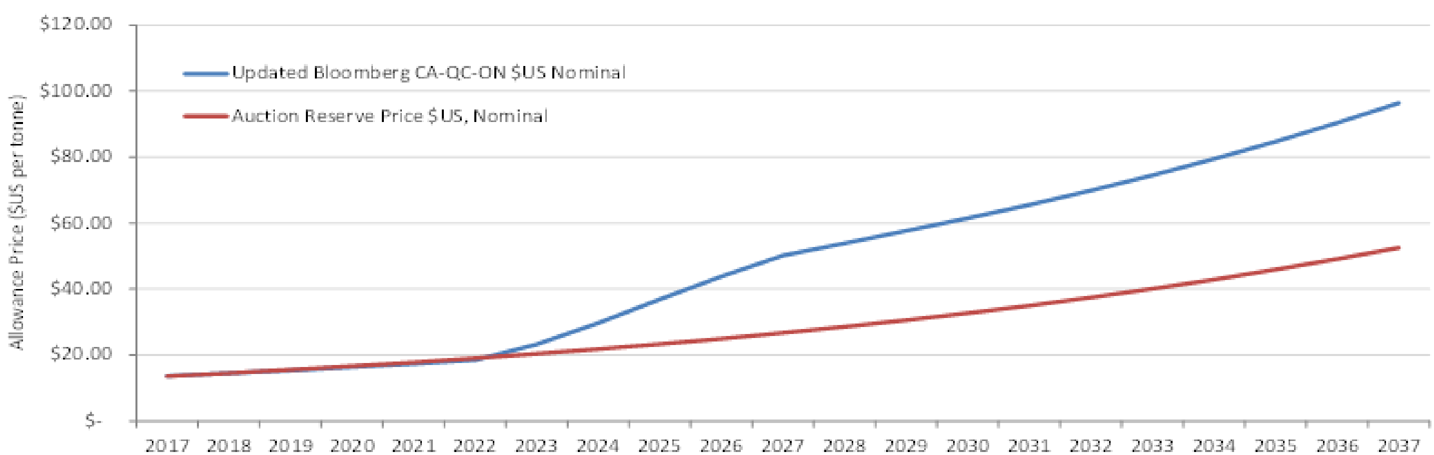
- The industrial rates and residential bill impacts will not reflect recycling of proceeds from the Cap and Trade program.
- The residential bills will be the base bills, prior to the application of the Ontario's Fair Hydro Plan.
- Application of the Ontario's Fair Hydro Plan to the residential bills will require specific guidance and direction from ENERGY.

Ministry of Energy’s 2017 Long-Term Energy Plan Modelling Assumptions, April 6 2017 Document (3)

Appendix Carbon price projection

															Assume same rate of increase as that observed from 2029 to 203						
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Updated CA-QC-ON ($US, Nominal) - Bloomberg Nov 2016 (Provided by ENERGY)	$13.62	$14.47	$15.39	$16.34	$17.37	$18.47	$23.21	$29.67	$36.85	$43.85	$50.13	$53.87	$57.60	$61.43	$65.50	$69.85	$74.49	$79.44	$84.71	$90.34	$ 96.33
Auction Reserve Price (aka Floor Price) ($US, Nominal) - Derived from Feb 2017 Auction Reserve Price, which is inflated by 5% plus inflation each year. Inflation assumed to be 2%. Reserve price is determined prior to each auction, and is taken as the higher of the CA and QC reserve price, converted to the same currency. The prevailing reserve price in a given year will depend on the exchange rate, as well as the inflation in each of the two jurisdictions.	$13.57	$14.52	$15.54	$16.62	$17.79	$19.03	$20.36	$21.79	$23.32	$24.95	$26.69	$28.56	$30.56	$32.70	$34.99	$37.44	$40.06	$42.87	$45.87	$49.08	$ 52.51



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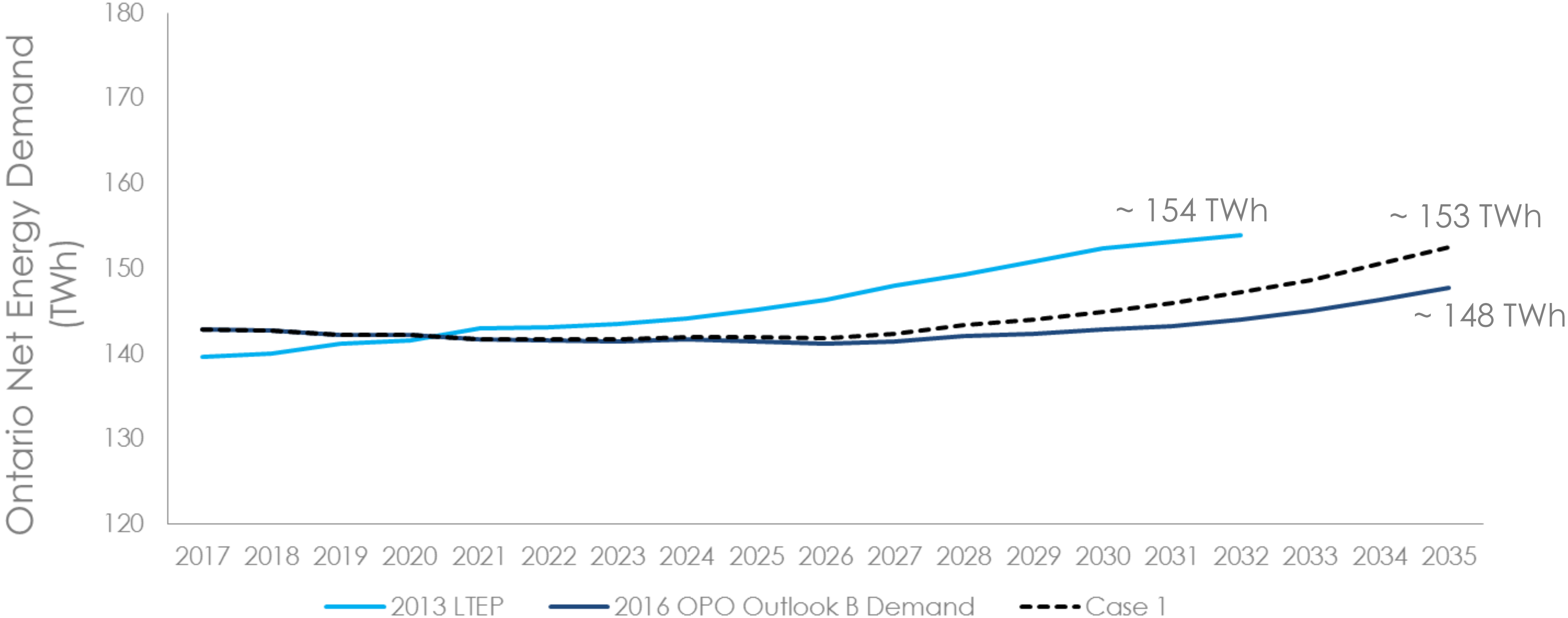
Case 1 and the 2016 OPO projected annual electricity demand to be higher in the near term than the 2013 LTEP, but lower in the long term



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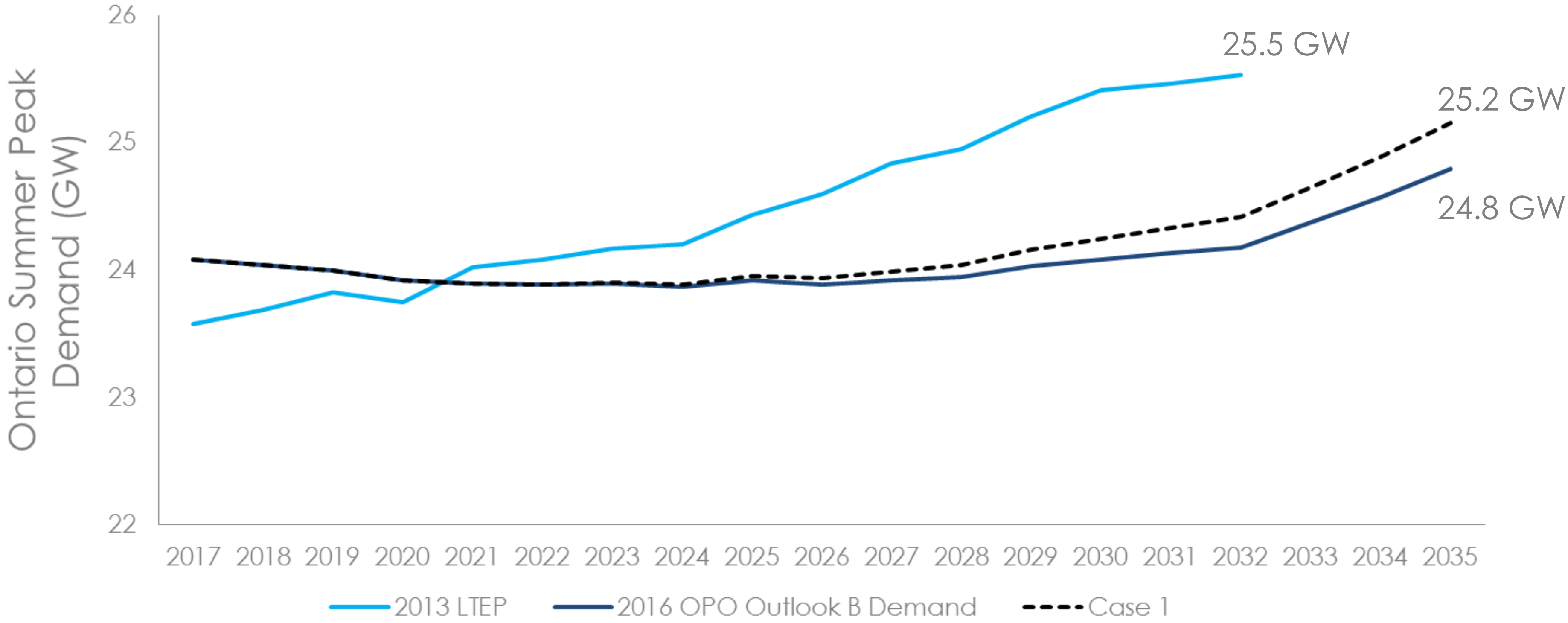
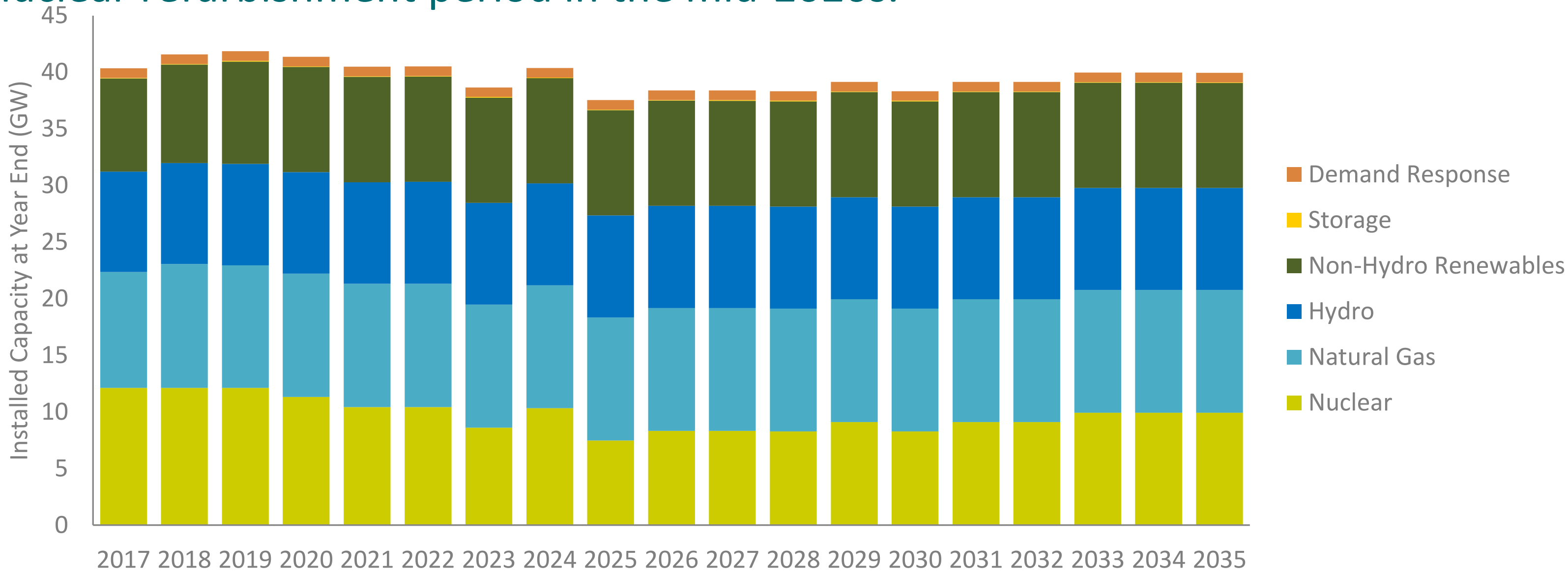
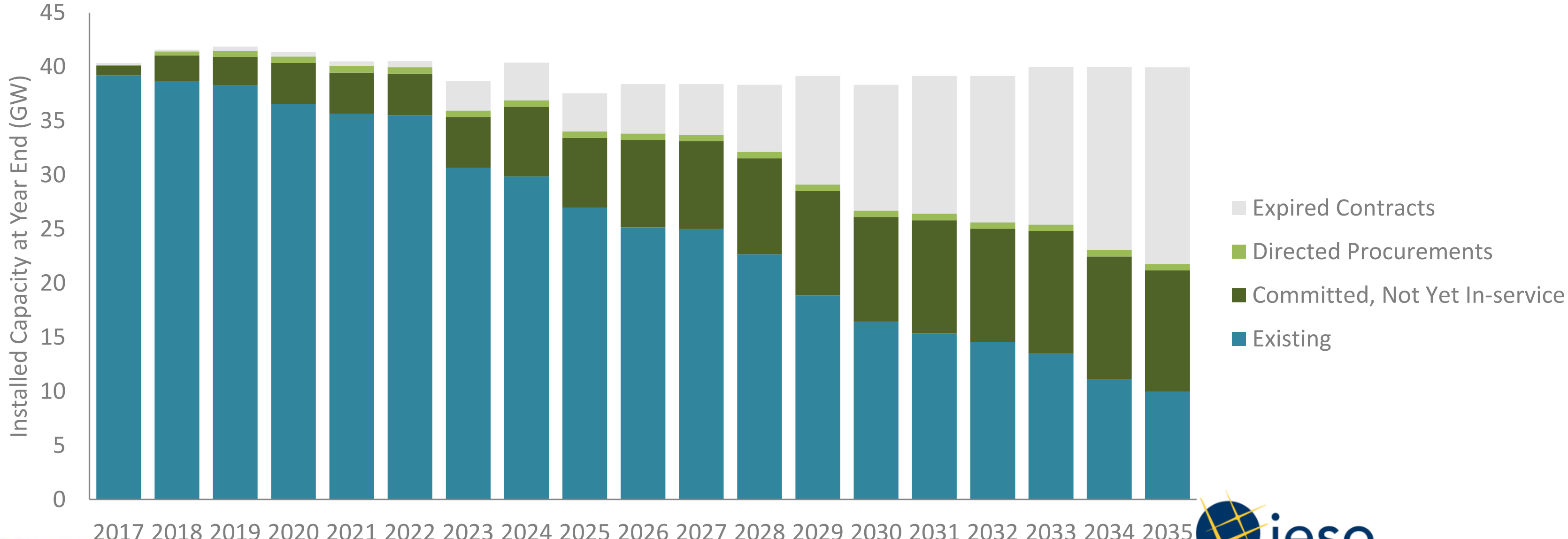
Likewise, projected summer peaks are higher in the near term in comparison to 2013 LTEP, but lower in the long term



Case 1 installed capacity would be about 40 GW over the planning outlook if all existing and planned resources remained available. Some net supply reductions would take place during the nuclear refurbishment period in the mid-2020s.





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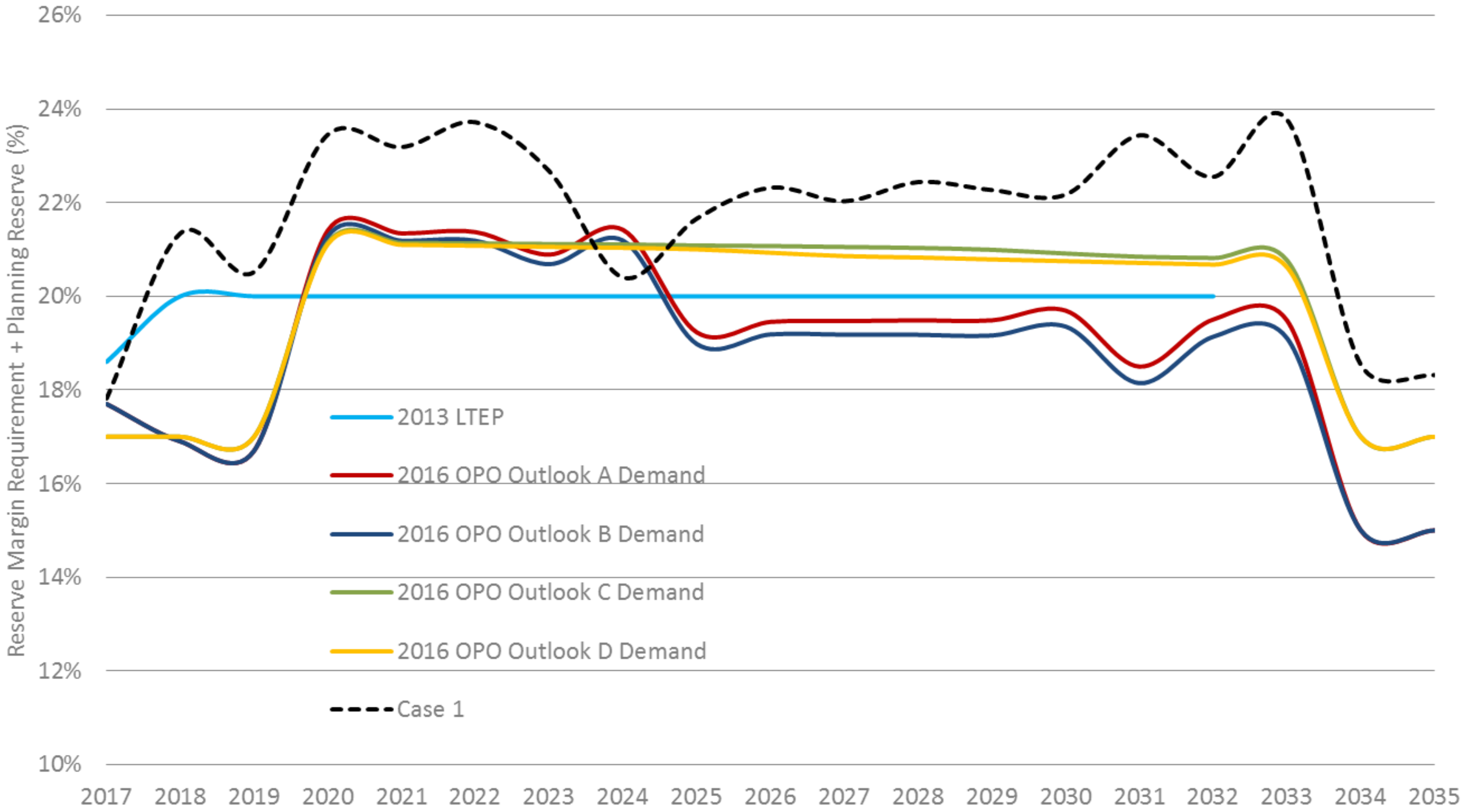
Case 1 and 2016 OPO include a 1,000 MW planning reserve from 2020-2033 to cover the risk nuclear refurbishment delays and performance decline due to an ageing generation fleet. The planning reserve was not reflected in the 2013 LTEP. The planning reserve and reserve margin requirement are combined below for a total reserve margin.



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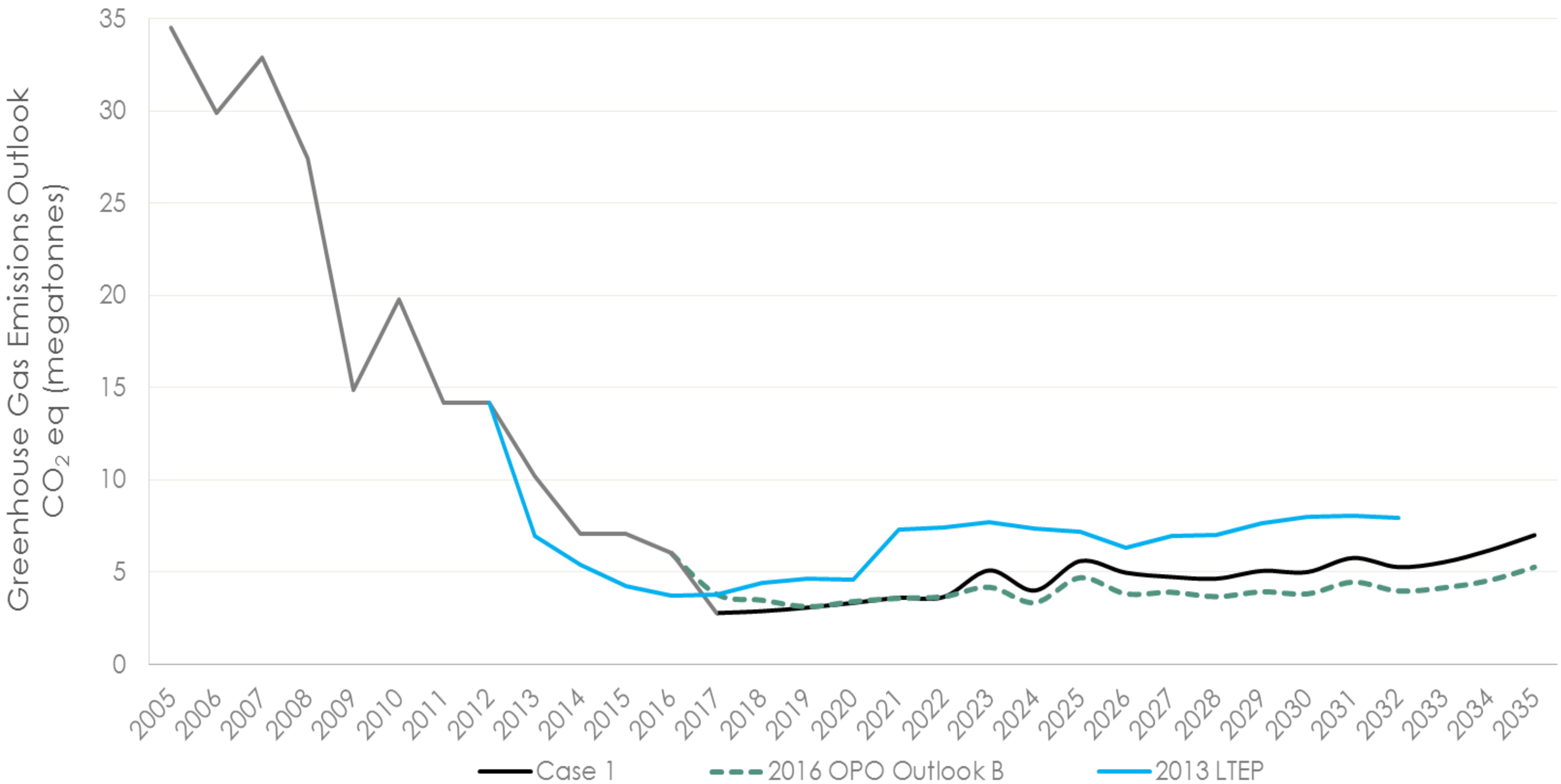
Under Case 1, electricity sector carbon dioxide emissions by 2035 would remain at levels comparable to those seen in recent years. Emissions outlooks are lower than the 2013 LTEP due to the Pickering extension in the early 2020's and decreased demand in the late 2020's.



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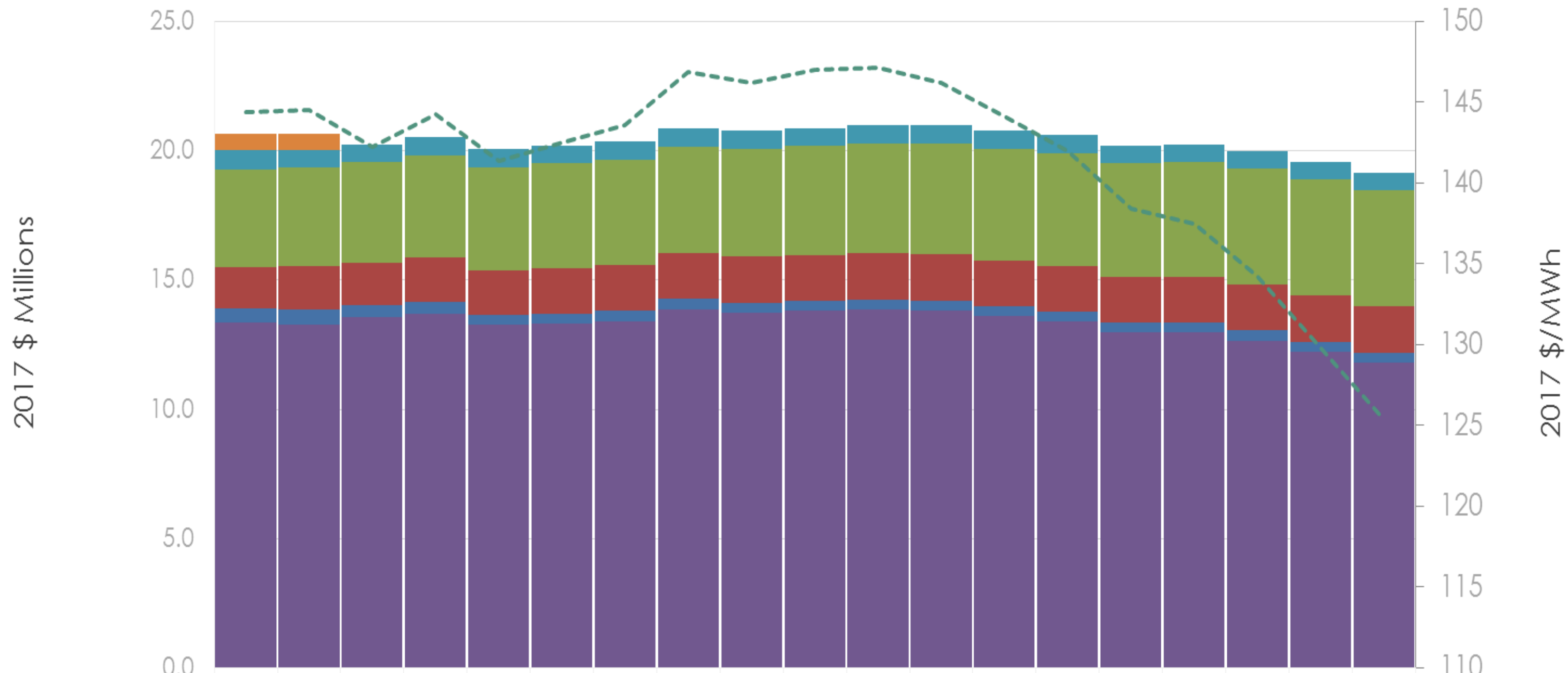
Case 1: Total Cost of Electricity Service is flat in real terms and declines in later years as existing contracts expire and new capacity requirements are obtained via a capacity market at costs that reflect the value of these assets and their existing physical infrastructure. The average unit cost of generation declines in real terms starting in 2027.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
DRC	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wholesale	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6
Distribution	3.8	3.8	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.5	4.5
Transmission	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Conservation	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Generation	13.4	13.3	13.5	13.7	13.3	13.3	13.4	13.9	13.7	13.8	13.9	13.8	13.6	13.4	13.0	13.0	12.7	12.2	11.8
Total	20.7	20.6	20.3	20.5	20.1	20.2	20.4	20.9	20.8	20.9	21.0	21.0	20.8	20.6	20.2	20.2	20.0	19.6	19.1
Average Unit Costs - Case 1	144.4	144.6	142.2	144.2	141.4	142.5	143.6	146.8	146.2	147.0	147.1	146.2	144.1	142.0	138.4	137.5	134.3	129.8	125.4

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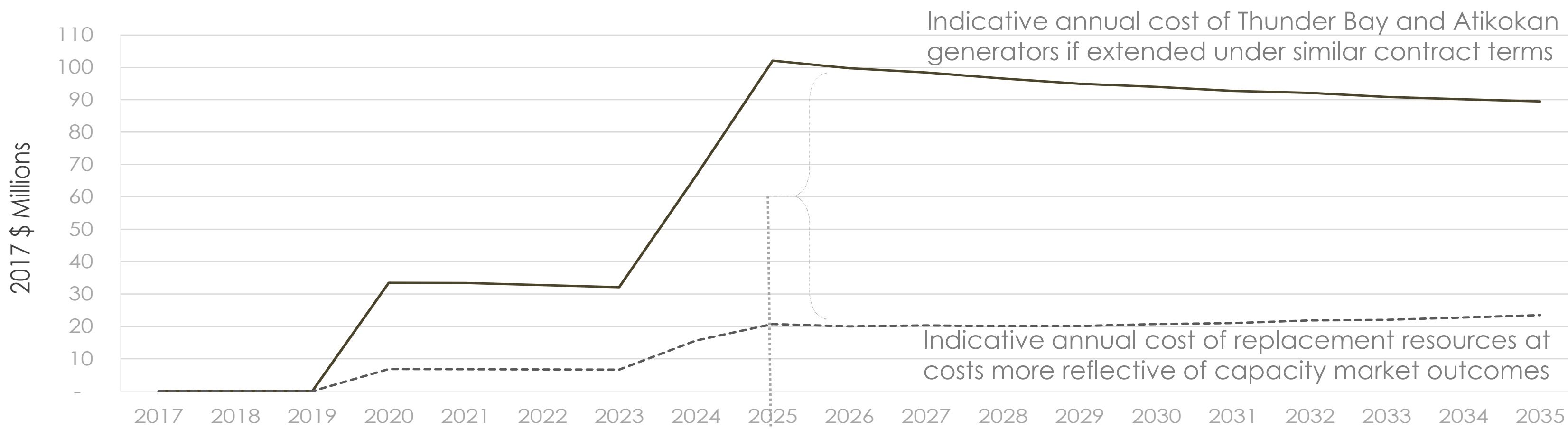
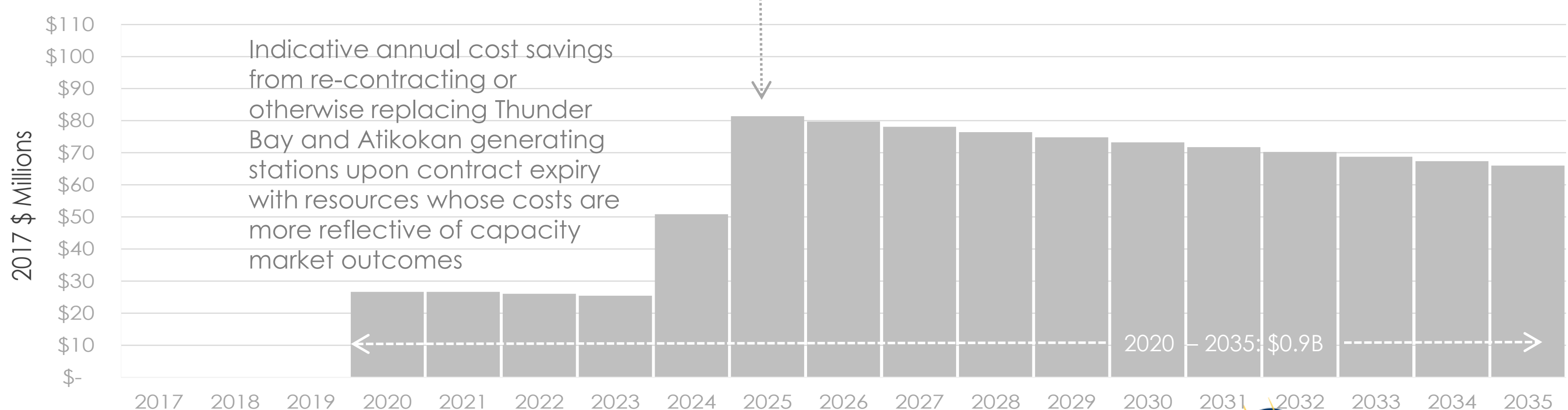
Case 2: At current contract rates, the Thunder Bay and Atikokan generating stations would cost between $30 Million and $100 Million per year between 2020 and 2035 if existing contracts were extended. If they were re-contracted or otherwise replaced at rates equal to an existing SCGT facility (i.e. more reflective of a capacity market cost outcome), cumulative savings of over $900 Million might be achieved.





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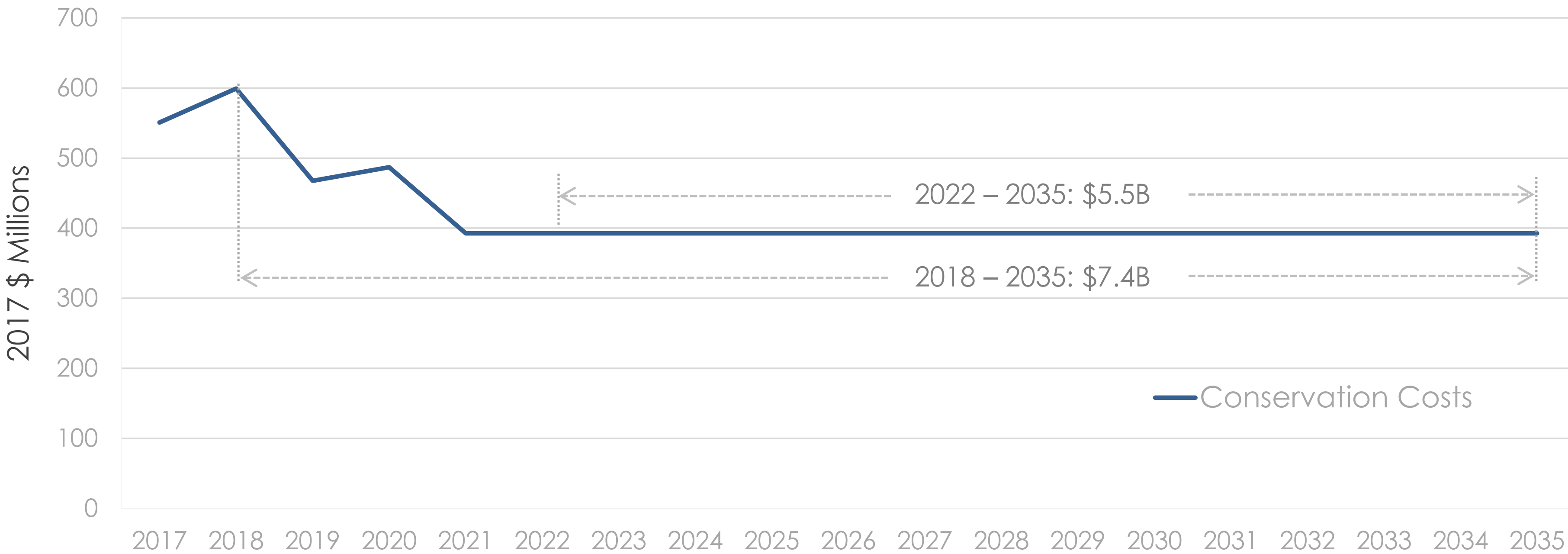
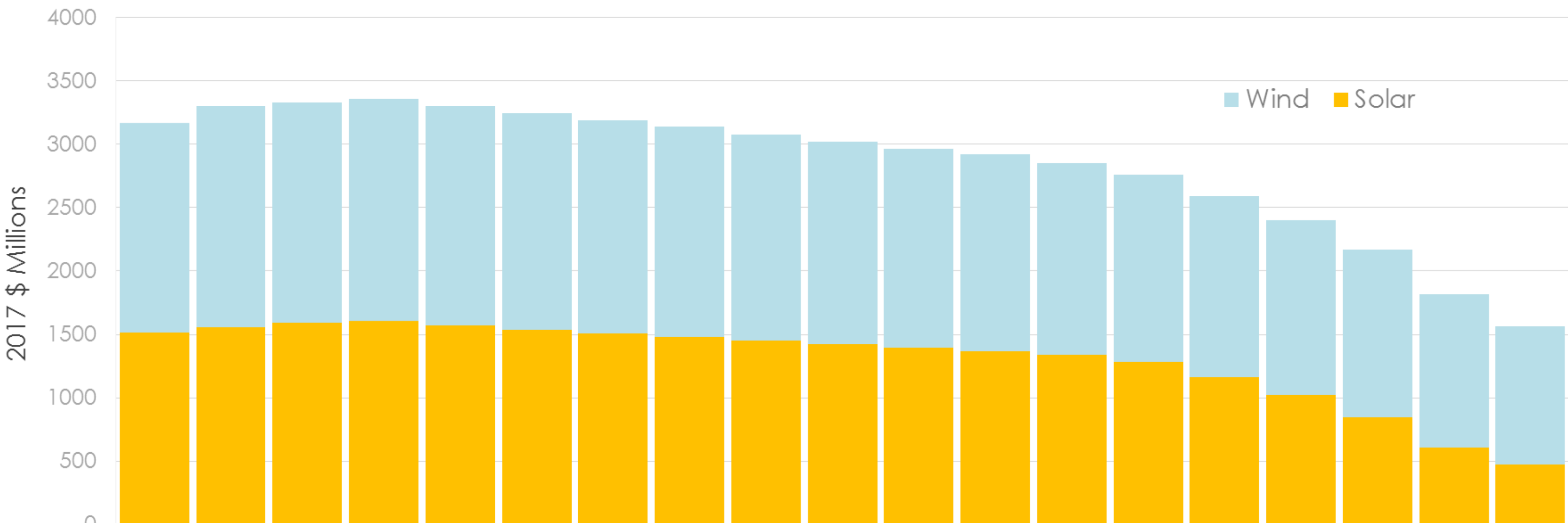
Case 3: Base case conservation costs are approximately $400M/year between 2021 and 2035. A total of about $7.4 B (2017$) could be shifted away from electricity ratepayers if conservation costs were funded by the GGRA starting in 2018.



Case 4: The total cost of wind and solar in Ontario is projected to range between $1.6 billion and $3.4 billion per year, for a cumulative total of approximately $54 billion by 2035. Shifting 10% of these costs to something like a GGRA would represent an average annual reduction of $285 million to electricity ratepayer costs.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Wind	1659	1750	1739	1758	1734	1706	1679	1660	1625	1598	1572	1551	1514	1479	1430	1376	1326	1212	1089
Solar	1511	1554	1593	1603	1570	1539	1509	1481	1450	1422	1394	1368	1335	1282	1165	1023	842	604	474
Total	3170	3304	3332	3361	3304	3245	3188	3141	3076	3020	2966	2920	2849	2761	2594	2399	2168	1815	1563

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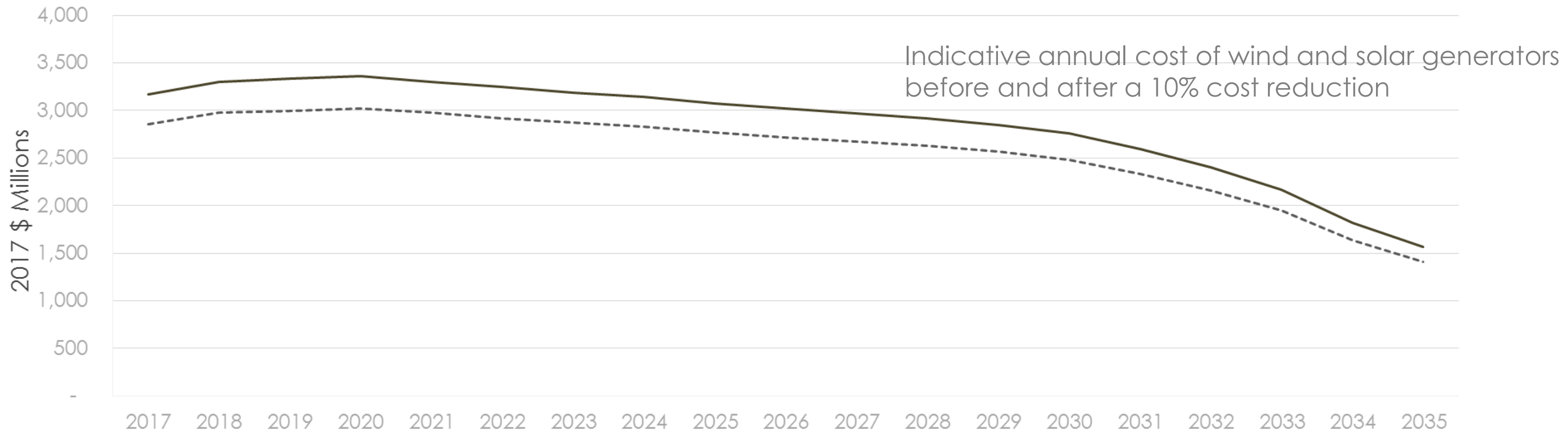
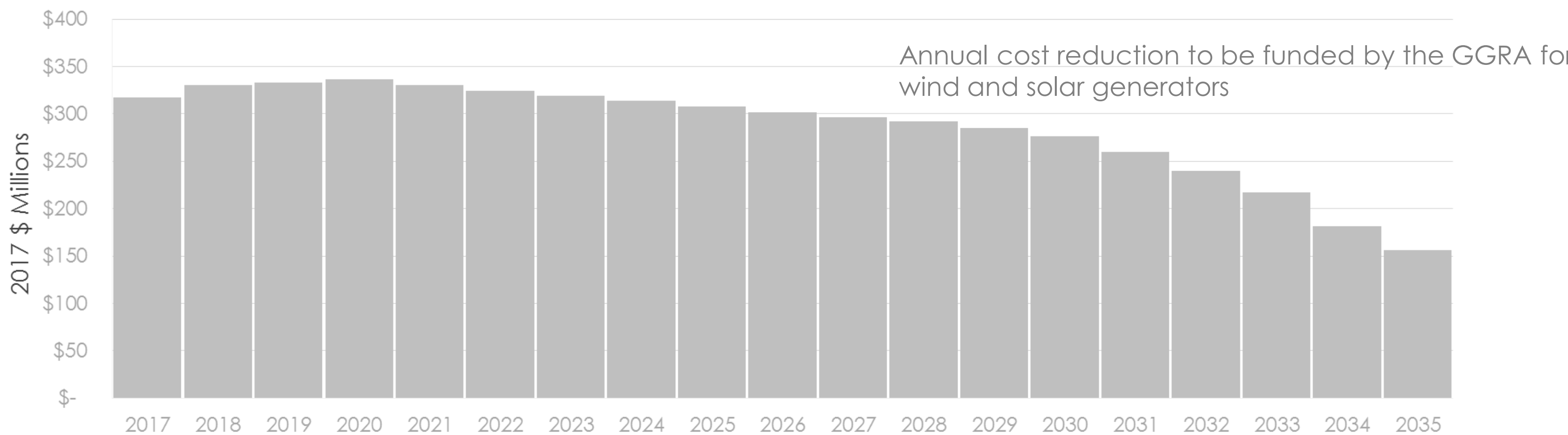
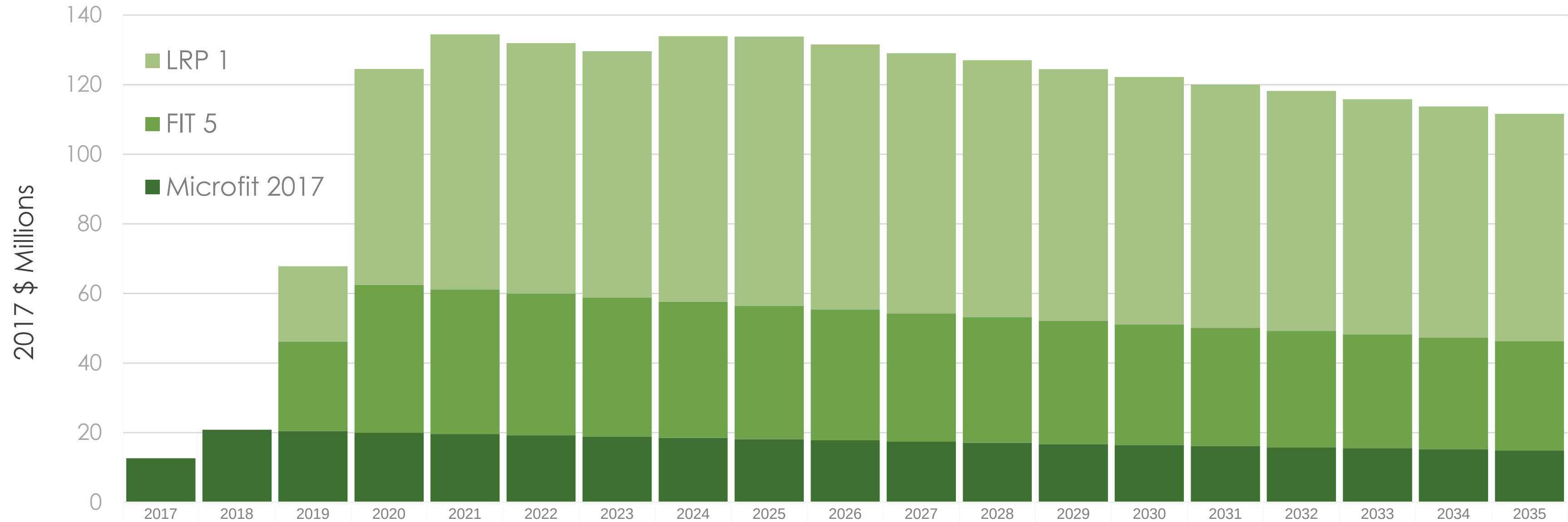
Case 4: The first figure below depicts the net difference in total annual costs of wind and solar before and after a 10% cost reduction. The funding amount required from the GGRA to decrease these annual costs would range between $150 Million and $350 Million per year.



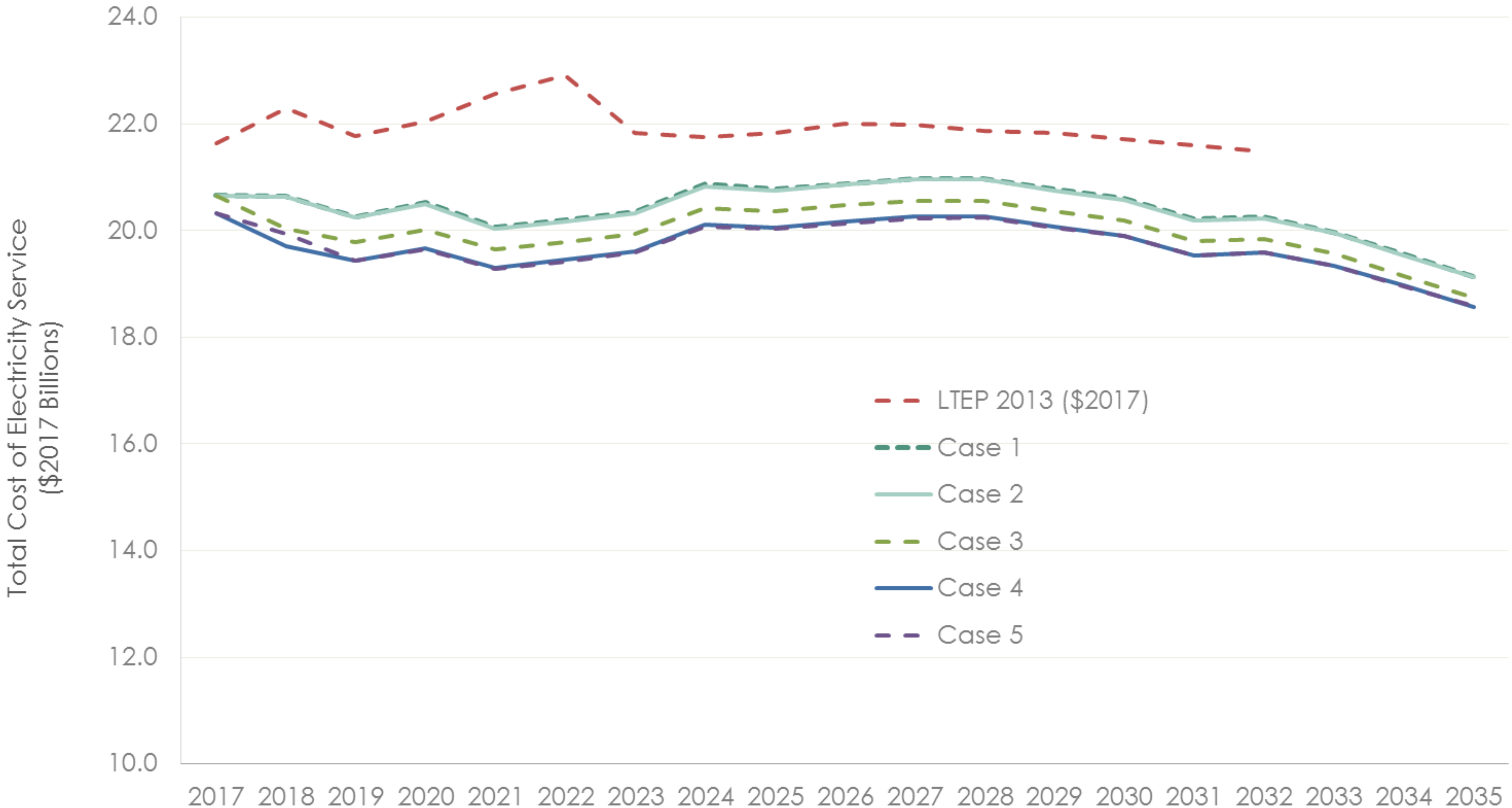


Case 5: MicroFit 2017, FIT 5 and LRP 1 would together cost more than $100 million per year starting in 2020, or approximately $1.5 billion cumulatively



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LRP 1			22	62	73	72	71	76	77	76	75	74	72	71	70	69	68	66	65
FIT 5			26	42	42	41	40	39	38	38	37	36	35	35	34	33	33	32	31
Microfit 2017	13	21	20	20	20	19	19	19	18	18	17	17	17	16	16	16	16	15	15
Total	13	21	68	125	134	132	130	134	134	132	129	127	124	122	120	118	116	114	112

Total Costs: For the highest total cost case, Case 1, the annual total cost is lower than the 2013 LTEP by $0.9 billion to $2.7 billion. The difference in annual costs between case 1 and 5 range between $300 million to $900 million over the planning period.



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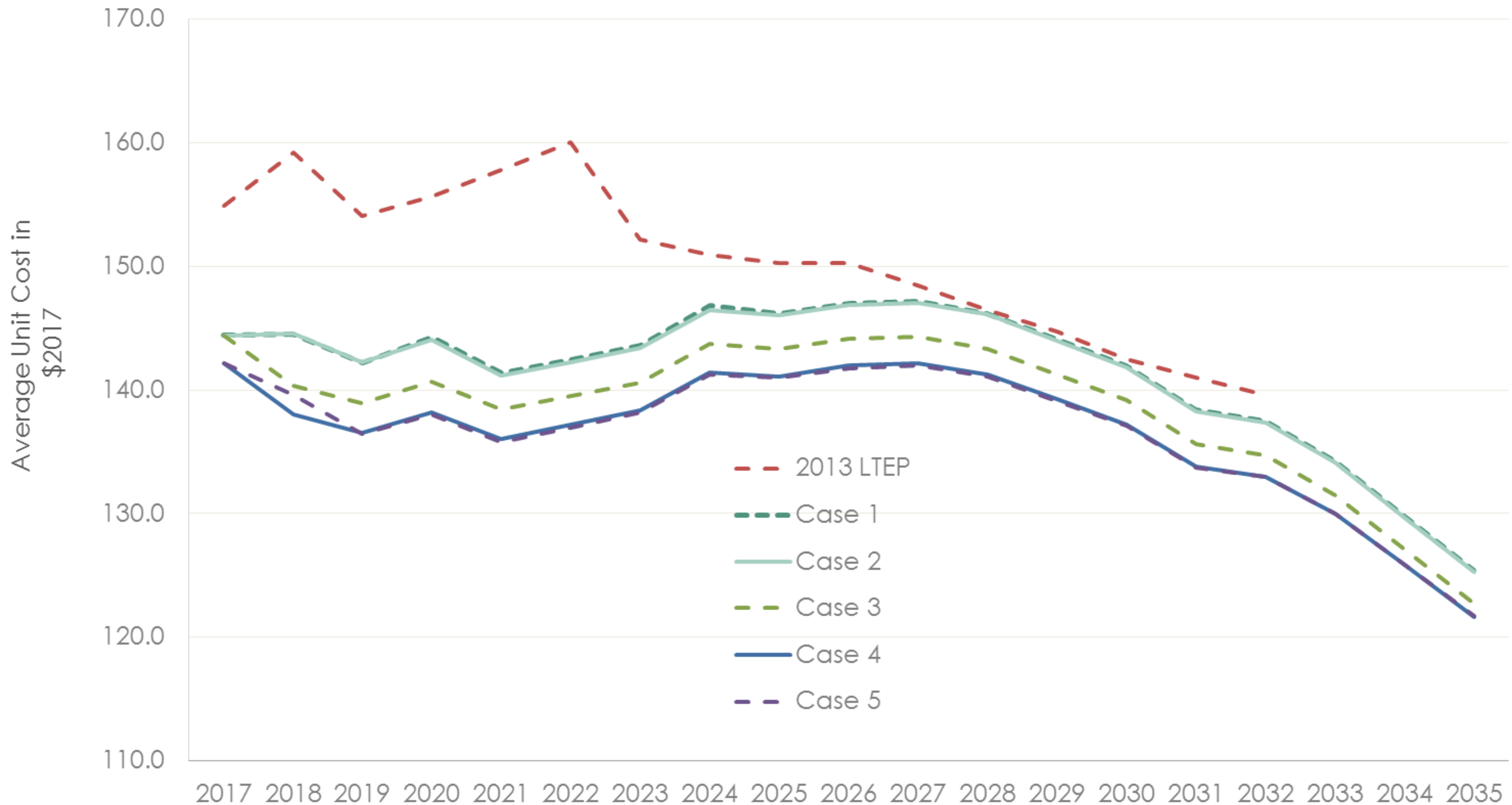
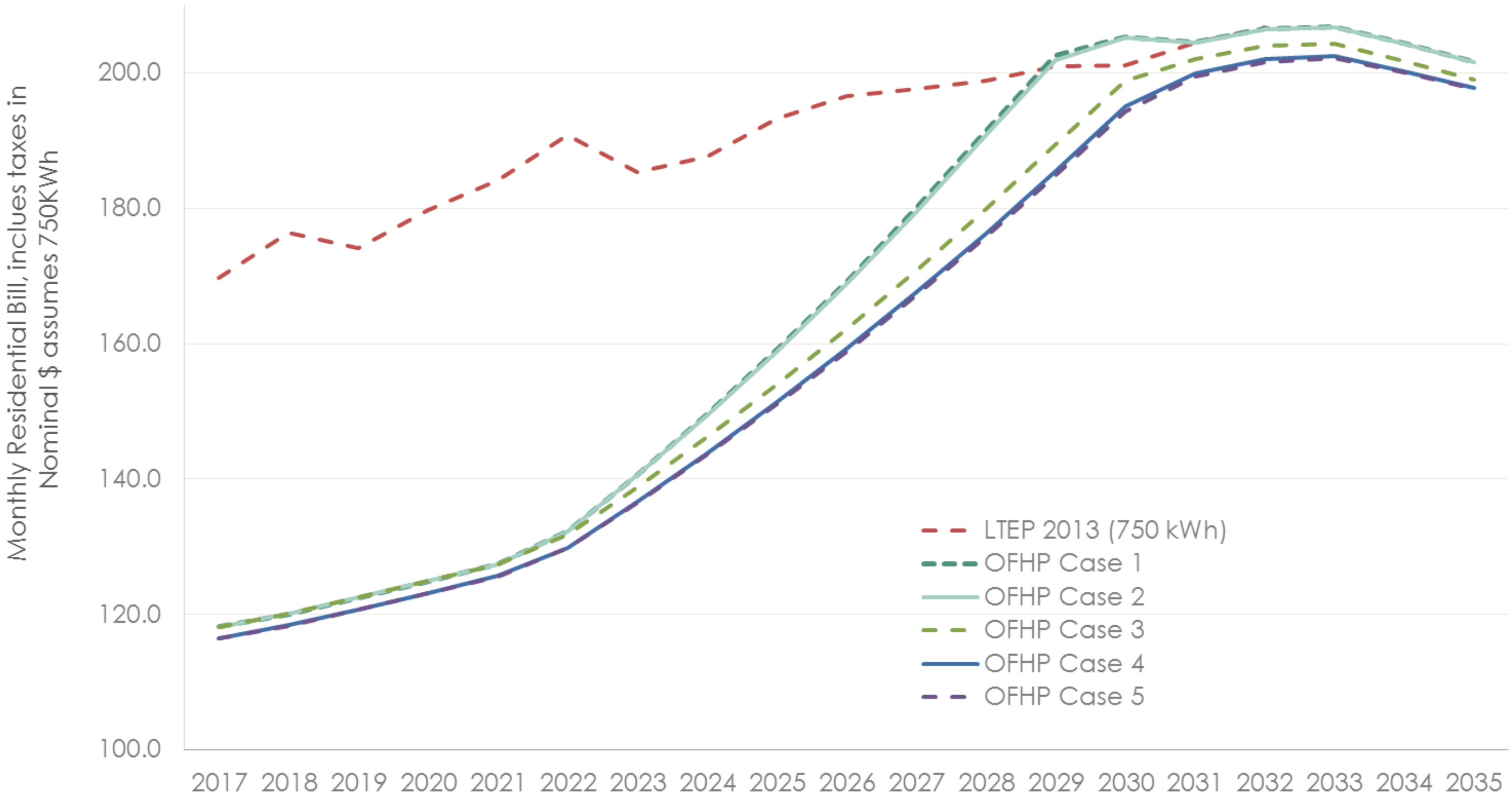
Average Unit Cost: For all cases, the annual average unit cost declines in real terms by 17% over the period due to increased demand and cost assumptions that decline in real terms. Cases 1 through 5 are less than the 2013 LTEP by approximately $2 to $6 per MWh by 2032, and decline markedly afterwards. The difference in average unit costs between case 1 and 5 is approximately $5 per MWh.



Monthly Residential Bills: For all cases with the OFHP, the 2017 monthly residential bill is approximately $117 dollars, which is lower than the 2013 LTEP by $53 dollars. Monthly residential bills increase between 5.3% to 6.3% year-over-year between 2022 and 2028. Residential bills will stabilize after reaching max debt. Cases 1 and 2 will be higher than the LTEP by $1 to $4 dollars for years 2029 and 2030. Cases 3 to 5 will be lower than the LTEP by $5 by the end of the forecast.



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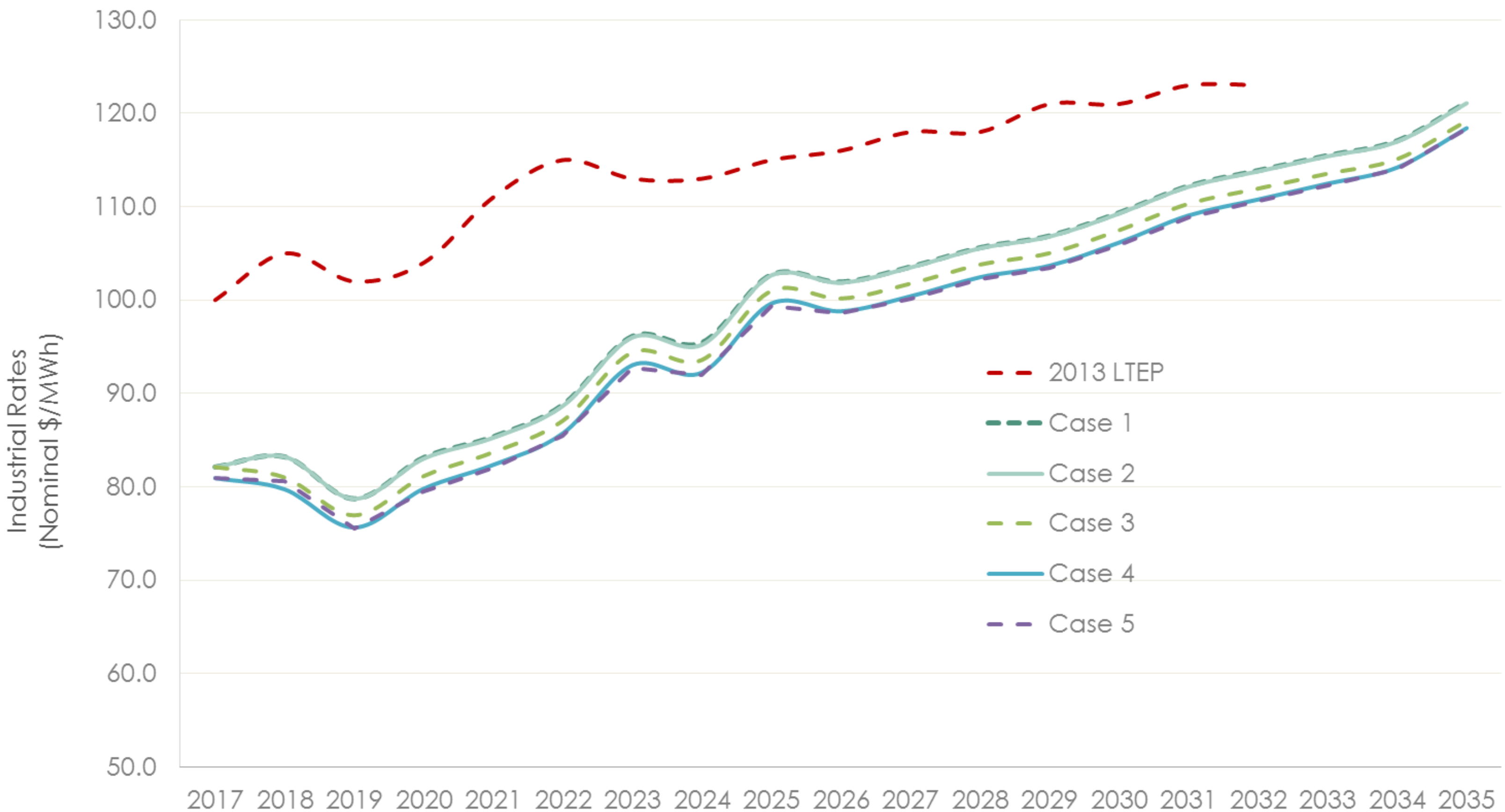
Industrial Rates: For the highest case, Case 1, industrial rates are lower than 2013 LTEP projections by between $9 and $26 dollars per MWh. The difference between Case 1 and 5 ranges between $1 to $4 dollars per MWh.



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Year-over-year rate increases over the planning horizon given different OFHP forecasts: Depending on the Case examined, lower costs result in a lower year-over-year increase in residential monthly bills after 2022. Lower cost forecasts also reach max debt later in the planning period and have lower total financing costs (interest plus debt borrowed). Once max debt is reached, monthly bills begin to stabilize with lower year-over-year increases

YoY Rate Increase for OFHP Forecast	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Ministry Cabinet Briefing Base Case		1.6%	2.0%	2.0%	2.0%	3.9%	6.4%	6.4%	6.4%	6.4%	6.4%	6.4%	4.0%	1.1%	1.3%	1.2%	1.0%	0.5%	-1.1%
OFHP Case 1		1.6%	2.0%	2.0%	2.0%	3.8%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	5.9%	1.4%	-0.4%	1.0%	0.2%	-1.2%	-1.3%
OFHP Case 2		1.6%	2.0%	2.0%	2.0%	3.8%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	5.9%	1.6%	-0.4%	1.0%	0.2%	-1.2%	-1.3%
OFHP Case 3		1.6%	2.0%	2.0%	2.0%	3.4%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.0%	1.6%	1.0%	0.1%	-1.2%	-1.4%
OFHP Case 4		1.6%	2.0%	2.0%	2.0%	3.3%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.1%	2.5%	1.1%	0.2%	-1.1%	-1.3%
OFHP Case 5		1.6%	2.0%	2.0%	2.0%	3.3%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.1%	2.7%	1.1%	0.3%	-1.1%	-1.2%

YoY Rate Increase for OFHP Forecast	Avg. 2023-2028	Avg. 2029-2035	Max Increase
Ministry Cabinet Briefing Base Case	6.4%	1.2%	6.4%
OFHP Case 1	6.3%	0.8%	6.3%
OFHP Case 2	6.3%	0.8%	6.3%
OFHP Case 3	5.3%	1.5%	5.3%
OFHP Case 4	5.2%	1.7%	5.2%
OFHP Case 5	5.2%	1.7%	5.2%

- For all OFHP forecasts the max year-over-year increase ranges between 5.2% to 6.3%